State of California
CALIFORNIA AIR RESOURCES BOARD

AMENDMENTS TO THE LOW CARBON FUEL STANDARD REGULATION AND TO THE REGULATION ON COMMERCIALIZATION OF ALTERNATIVE DIESEL FUELS

FINAL STATEMENT OF REASONS

November 2018

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State of California
AIR RESOURCES BOARD

Final Statement of Reasons for Rulemaking,
Including Summary of Comments and Agency Response

PUBLIC HEARING TO CONSIDER THE PROPOSED AMENDMENTS TO THE LOW CARBON FUEL STANDARD REGULATION AND TO THE REGULATION ON COMMERCIALIZATION OF ALTERNATIVE DIESEL FUELS

Public Hearing Dates: April 27, 2018 and September 27, 2018
Agenda Item No.: 18-3-3 and 18-7-4

I. GENERAL

A. Action Taken in this Rulemaking

The Staff Report: Initial Statement of Reasons for Rulemaking (staff report), entitled "Public Hearing to Consider Proposed Amendments to the Low Carbon Fuel Standard Regulation and to the Regulation on Commercialization of Alternative Diesel Fuels," released March 6, 2018, is incorporated by reference herein. The staff report, which is incorporated by reference herein, contained a description of the rationale for the proposed amendments. On March 6, 2018, all references relied upon and identified in the staff report were made available to the public.

In this rulemaking, the California Air Resources Board (CARB or Board) is adopting amendments to the Low Carbon Fuel Standard (LCFS) and to the Regulation on Commercialization of Alternative Diesel Fuels (ADF), which set ambitious targets for low carbon fuel use from the transportation sector—the amendments target a 20 percent reduction in fuel carbon intensity (CI) from a 2010 baseline by 2030. The amendments also improve the efficiency of the program—reducing application time, streamlining and further clarifying reporting requirements, creating additional flexibility for program participants, and creating more opportunities for low carbon fuel providers.

The amendments were developed pursuant to the requirements of Senate Bill (SB) 32 (Pavley, 2016), which codifies a statewide greenhouse gas (GHG) target of at least 40 percent below 1990 levels by 2030. In December 2017, the Board adopted a strategy for achieving this target, known as *California's 2017 Climate Change Scoping Plan* (2017 Scoping Plan). The 2017 Scoping Plan made it clear that developing a more ambitious LCFS is a critical part of the state's efforts to achieve the SB 32 goals.

A 2017 Court of Appeal opinion concluded that CARB, in the 2015 LCFS re-adoption, had failed to adequately analyze under the California Environmental Quality Act (CEQA) potential NOx impacts that may have been caused by increased use of biodiesel driven by the LCFS. On October 18, 2017, the Fresno County Superior Court issued a writ of mandate pursuant to the direction of the Court of Appeal. To comply with this writ,

CARB set aside its approval of the parts of the 2015 LCFS environmental analysis addressing NOx emissions from biodiesel on November 17, 2017, and has developed a supplemental environmental disclosure analysis to more comprehensively address potential LCFS-driven biodiesel NOx emissions impacts. Staff developed the proposed amendments to the ADF regulation based on this new supplemental analysis to ensure long-term mitigation of any potential NOx emissions that could be associated with biodiesel use that might be driven by the LCFS.

The amendments to the Regulations were initiated with the publication of a notice in the California Notice Registrar on March 6, 2018, and notice of an initial public hearing scheduled for April 27, 2018.[1] The staff report, full text of the proposed regulatory language, and other supporting documentation were made available for public review on March 6, 2018, and for comment, starting on March 9, 2018, with additional oral and written comments submitted at the April 27, 2018, Board hearing. The text of the originally proposed regulation was included in Appendix A of the staff report. The regulatory amendments as proposed would:

- Strengthen the carbon intensity benchmarks through 2030 in order to help achieve the SB 32 2030 GHG target;
- Expand the fuel types to which the LCFS regulation applies in order to encourage additional actions in areas where reductions will be needed to meet long-term GHG goals;
- Improve accuracy and add flexibility to incent the installation of additional low-CI electricity supply coupled with the expansion of ZEV fueling infrastructure;
- Adopt accounting and permanence protocols to enable credit generation for carbon capture and sequestration projects;
- Improve crediting for innovative actions at conventional fuel refineries;
- Further ensure accuracy of the data that underlies the LCFS program and associated market;
- Simplify and streamline application and reporting requirements for regulated entities to encourage greater participation and assist participant compliance;
- Update regulatory values (e.g., EER, energy densities) and LCA modeling tools to use more detailed or recent data;
- Include an independent third-party verification and verifier accreditation program to ensure accuracy of LCFS reported data, and reduce requirements for regulated entities to submit demonstrations and documents to CARB for staff review;
- Address court direction, and

[1] California Air Resources Board. Notice of Public Hearing to Consider Proposed Amendments to the Low Carbon Fuel Standard Regulation and to the Regulation on Commercialization of Alternative Diesel Fuels. Posted March 6, 2018. Available online at: https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm.

- Make minor updates for typographical errors, clarifications, and organization of the rule that do not materially affect requirements.

At its initial April 27, 2018, public hearing, the Board was informed of the proposed amendments to the LCFS and ADF regulations. The Board did not take action on the proposal at the April 2018 Board Hearing, but directed the Executive Officer, through Resolution 18-17, to determine if additional conforming modifications to the regulation were appropriate and to make any proposed modified regulatory language available for public comment, with any additional supporting documents and information, for a period of at least 15 days in accordance with Government Code section 11346.8. The Board further directed the Executive Officer to consider written comments submitted during the public review period and make any further appropriate modifications available for public comment for at least 15 days. The Executive Officer was directed to evaluate all comments received during the public comment periods, including comments raising significant environmental issues, and prepare written responses to such comments as required by CARB's certified regulations at California Code of Regulations, title 17, sections 60000-60007 and Government Code section 11346.9(a). The Executive Officer was further directed to present to the Board, at a subsequently scheduled public hearing, staff's written responses to environmental comments and the final environmental analysis for consideration for approval, along with the finalized amendments for consideration for adoption.

B. Mandates and Fiscal Impacts to Local Governments and School Districts

The Board has determined that this regulatory action will not result in a mandate to any local agency or school district the costs of which are reimbursable by the state pursuant to Part 7 (commencing with section 17500), Division 4, Title 2 of the Government Code.

The amendments will affect State and local government finance through changes in taxes collected from fuel sales, changes in fuel expenditures for governments' fleets, cost-savings from reduced health impacts and changes of revenues from the sale of LCFS credits generated by local governments.

The amendments are expected to lead to overall increases in the tax revenues generated from fuel sales for both the State and local governments, mainly due to higher gasoline and diesel prices resulting from the amendments. However, in 2019 to 2022, tax revenues from fuel sales are expected to decrease due to lower gasoline and diesel prices relative to business-as-usual, which result from the smoothing of the CI schedule in this period. Overall, from 2019 to 2030, the proposed amendments are expected to increase State and local governments' tax revenues by $110 million and $446 million, respectively.

The change in fuel prices could also affect State and local governments' finances by changing the fuel expenditure of State and local fleets. By 2030, it is expected that the State fleet fuel expenditure could increase by $8 million and the local governments' fleet fuel expenditure could increase by $42 million.

The amendments are also expected to result in health benefits due to improved air quality. These health benefits are expected to lead to cost-savings due to decreased hospital and emergency room visits and reduced sick days for state and local government employees.

The amendments are also expected to increase the revenues generated by local governments from the sale of LCFS credits generated primarily from the use of low-CI fuels in public transit systems. The proposed amendments are expected to increase local governments' revenues from the sale of LCFS credits by $593 million from 2019 to 2030. However, some of the increased revenues from selling LCFS credits may be used to purchase more expensive low-CI fuels or as an investment in fueling infrastructure or equipment to utilize these low-CI fuels.

C. Consideration of Alternatives to the Proposed Amendments

Staff is required to consider alternatives to the proposed amendments for the Low Carbon Fuel Standard Regulation. For the reasons set forth in the Staff Report, in staff's comments and responses at the hearing, and in this FSOR, the Board determined that no alternative considered by the agency would be more effective in carrying out the purpose for which the regulatory action was proposed, or would be as effective and less burdensome to affected private persons, or would be more cost-effective to affected private persons and equally effective in implementing the statutory policy or other provisions of law than the action taken by the Board. Further, none of the options that would have enabled California to meet the SB 32 goals were as cost effective as the proposed Regulation and substantially address the public problem stated in the notice.

The Executive Officer analyzed two alternatives to the proposed regulation. The first alternative is more aggressive than the proposed amendments and achieves a 25 percent CI reduction in 2030. Similar to the proposed amendments, the compliance trajectory for this alternative is smoothed by linearly reducing the benchmarks between the current 5 percent reduction in 2018 to a 25 percent reduction in 2030. The second alternative achieves an overall CI reduction target of 18 percent by 2030 but does not smooth the compliance trajectory, instead maintaining the current compliance targets through 2022 and the decreases targets linearly to an 18 percent reduction in 2030.

The first alternative would achieve higher GHG reduction than the proposed amendments, but at a significantly higher cost to the California economy and consumers. The cost effectiveness of this alternative was estimated to be $230/MTCO$_2$e as compared to $32/MTCO$_2$e for the proposed amendments.

The second alternative would result in similar GHG reduction as the proposed amendments but at a higher cost to the California economy and consumers. The cost effectiveness of the second alternative was estimated to be $89/MTCO$_2$e as compared to $32/MTCO$_2$e for the proposed amendments.

For a more detailed description of the alternatives, please see Chapter IX of the ISOR and Appendix E (Summary of DOF Comments to the LCFS 2018 Amendments SRIA and CARB Responses).

II. MODIFICATIONS MADE TO THE ORIGINAL PROPOSAL

A. Modifications Approved at the Board Hearing and Provided for in the 15-Day Comment Periods

Pursuant to Board direction provided at the April 27, 2018 meeting, CARB released Notices of Public Availability of Modified Text and Availability of Additional Documents and Information (15-Day Notices) on June 20, 2018, and August 13, 2018, which notified the public of additional documents added into the regulatory record and presented additional modifications to the regulatory text after consultation with stakeholders.[2]

B. Non-Substantial Modifications to the Regulation and Documents

Subsequent to the 15-day public comment periods mentioned above, staff identified the following additional non-substantive changes to the regulation:

- Updated cross references:
  - Section 95483(c)(6): Corrected “section 95488.9(g)”, which does not exist, to “section 95488.7(a)(3)”
  - Section 95483.2(b)(3)(F): Corrected “section 95483(a)(2)(F)” which does not exist, to “section 95483(b) and (c)”
  - Section 95483.2(b)(7)(D): Corrected “section 95483.4(b)” which does not exist, to “section 95483.2(b)”
  - Section 95486.1(e): Corrected “sections 95483(c)(4) to (7),” to the corresponding renumbered “sections 95483(c)(3) to (6).”
  - Section 95488.5(d)(2): Corrected “95488.5(d)(2)” to “95488.5(d)(1)”
  - Section 95489(f)(3) and (4): Corrected “section 95489~~(g)~~(f),” to “section 95489~~(g)~~(f)” to show the updated subsection letter in underline format
  - Section 95491(f)(3): Corrected “sections 95491(d)~~(a)(3)~~ and (a)(4)” to “sections 95491(d)~~(a)(3)~~ and (e)~~(a)(4)~~”
  - Section 95501(a)(4): Corrected “section 95503(f),” which does not exist, to "95503(e)"
- Section 95481(a)(10) and section 95488.5(f): Corrected date of the Avoided Cost Calculator document incorporated by reference from March to May. No March 2018 version of the model exists
- Section 95481(a)(26): Capitalized the letter “O” in the definition of “CHAdeMO Connector”

[2] California Air Resources Board. Notices of Public Availability of Modified Text and Availability of Additional Documents. Posted June 20, 2018 and August 13, 2018. Available online at: https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm

- Section 95481(a)(44): Deleted stray “s” in the abbreviation of “Electric Transport Refrigeration Units (eTRU)”
- Section 95481(a)(125): Corrected the spelling of the acronym for liquefied petroleum gas, to “LPG”
- Section 95481(a)(139): Restored regulation text proposed to be deleted, in strikethrough format, to demonstrate a proposed deletion of regulatory text. Although the related proposed modification was included in the proposed modified regulation order, the strikethrough of text proposed to be deleted or replaced was inadvertently omitted in the original proposal's definition of “Transaction Quantity”
- Section 95483(c)(4) through (7): Updated numbering to include the omitted number (3)
- Section 95483.1(a)(1)(C): Restored current regulation text that was inadvertently deleted in the original proposal, and updated the numbering and cross reference: “~~(D)~~4. The fuel delivered under subsection ~~(C)~~3. is shown to have been sold for use in California or was otherwise actually used in California; and”
- Section 95483.1(b): Restored current regulation text proposed to be deleted, in strikethrough format: ~~“The procedure for opting into and opting out of the LCFS for such a person is set forth as follows.”~~
- Section 95487(a)(1)(B): Restored text that was amended correctly in the original proposal, but was inadvertently deleted in the June 20 and August 13, 2018 modifications: “(B) ~~a~~Acquire or transfer LCFS credits. A third-party~~ entity~~, which is not a regulated ~~party~~ entity or acting on behalf of a regulated ~~party~~ entity, may not hold, purchase, sell, or trade LCFS credits, except as otherwise specified in section 95483. ~~subsection (C), below; and~~”
- Section 95487(a)(2)(B): Relocated text that was described in the June 20, 2018 notice, which was inadvertently pasted in section 95487(a)(1)(B) of the modified regulation order. The following text has been moved to (2)(B), as described in the June 20 notice, to read: “A regulated entity may not: …(B) Borrow or use credits from anticipated future carbon intensity reductions to demonstrate compliance pursuant to section 95485(a). This does not preclude contracting for future delivery of LCFS credits as described in section 95487(b)(1)(B).”
- Section 95488.3(b): Deleted stray parenthesis
- Section 95488.5(f), Table 7-2: Changed footnote asterisk (*) to footnote number 3 for consistency with Table 7-1
- Section 95489(d)(5): Deleted “later” which was inadvertently not shown in strikethrough format, appearing at the end of a large section of text shown in strikethrough format
- Section 95489(e)(5): Restored current regulation text, in strikethrough format, that was inadvertently deleted in the original proposal: Restored “must” and “(A).” Deleted “(1)” and “annually”

- Section 95491(f): Deleted stray parenthesis
- Section 95491(d)(3)(C)2.a.: Replaced stray "; and" with period "."
- Section 95491(d)(4): Restored current regulation text, in strikethrough format, that was inadvertently shown as proposed text (in double underline and strikethrough format) in the August 13, 2018 modifications: "~~For each private access fueling facility, the~~"
- Section 95491: Added "NOTE: Authority Cited…", which was inadvertently omitted when the new section 95491.1 was created
- Section 95491.1(b)(2): Removed strikethrough of parenthesis preceding the subsection number 2: "~~(B)(~~2)" is corrected to "~~(B)~~(2)"
- Section 95491.1(b)(2)(A) and (B): Deleted period following the subsection letters (A) and (B): "~~1~~(A)." is corrected to "~~1.~~(A)" and "~~2~~(B)." is corrected to "~~2.~~(B)"
- Section 2293.6(a)(4)(A) [in the ADF regulation]: Corrected format of the added text, "and related tools" which was formatted as current regulatory text in the original proposal
- Section 2293.6(a)(5)(C): Removed strikethrough of "and" in the cross-reference to section 2293.6(a)(5)(A) and (B)
- Appendix 1 of Subarticle 2. [in the ADF regulation]: Corrected format of the added text, "(the listed ASTM methods are incorporated herein by reference)" which was formatted as current regulatory text in the original proposal
- Subsection A.2(a)(81) [in Appendix B CCS Protocol]: Corrected the spelling of the word "capital" in the definition of "net working capital"
- Subsection C.9(c): Changed the word "insure" to "ensure," to fix a grammatical mistake
- Section C: Fifteen instances of "AOR" were replaced with "surface projection of the storage complex." In the 2nd 15-day changes, staff proposed to delete the definition of "area of review" or "AOR," and replace the term throughout the rest of the Protocol with the phrase "the surface projection of the storage complex." "AOR" was changed in the majority of cases; however, multiple references to "AOR" remained in the document that was published on August 13, 2018. This error has now been corrected.

The above described modifications constitute non-substantial changes to the regulatory text because they more accurately reflect the numbering of a section and correct spelling and grammatical errors, but do not materially alter the requirements or conditions of the proposed rulemaking action.

C. Revisions to Citations of Documents Referenced in the Rulemaking Action

Subsequent to the 15-day public comment periods mentioned above, staff made additional non-substantial modifications to the citations to certain documents referenced in this rulemaking action as explained in greater detail below.

1. Documents referenced in Chapter III of the ISOR (March 6, 2018):

   - *Calculation of Proposed Energy Economy Ratio under the Low Carbon Fuel Standard Regulation. CARB, November 2014.* The title given was incomplete, and is corrected to include: "for Electric Buses"
   - *eGRID2014 Version 2, U.S. EPA, accessed on December 13, 2017. Available at: https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid*. The reference did not provide the full title of U.S. EPA's database. However, the correct citation was given in the ISOR list of references for Appendix C-3 as: *Emissions & Generation Resource Integrated Database (eGRID) - U.S EPA Webpage, Revised Release (v2): 2/27/2017. Last updated June 1, 2017.* The update to the revised release version was also noticed in the June 20, 2018 Notice of Proposed Modifications, under section E. Modifications to Section 95484 (p.6)
   - *Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. [Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)]. IPCC, Geneva, Switzerland, 151 pp. IPCC, 2014.* The title was incomplete, and is corrected to include "Climate Change 2014: Synthesis Report"
   - *California Senate Bill No. 32. Pavley 2016.* The reference did not provide the full title of the bill, and is corrected to include "Global Warming Solutions Act of 2006 (Health and Safety Code Section 38566)." This reference was also cited in ISOR Appendices D, G, the Final Environmental Analysis, and the Final Supplemental Disclosure Discussion

2. Documents referenced in Chapter V of the ISOR (March 6, 2018):

   - *Integrated Science Assessment (ISA) for Particulate Matter (Final Report, Dec 2009). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-08/139F. U.S. EPA. Final Report, December 2009.* The U.S. EPA updated the Final Report to include errata. The citation date is corrected to February 2010

3. Documents referenced in Appendix C of the ISOR (March 6, 2018):

   - *See also vehicle category Definitions.* This note was included beneath a reference to a U.S. EIA Alternative Fuel Vehicle Data website, but did not provide the full title of the Definitions website, and is corrected to include: Definitions, Alternative Fuel Vehicle Data. U.S. Energy Information Administration Website.

Available: http://www.eia.gov/renewable/alternative_transport_vehicles/pdf/defs-sources-notes.pdf

4. Documents referenced in Appendix D of the ISOR (March 6, 2018):

   - *2017 California Air Resources Board. Final Regulation Order. Subchapter 10 Climate Change, Article 4 Regulation to Achieve Greenhouse Gas Emission Reductions, Subarticle 7 Low Carbon Fuel Standard. Available: https://www.arb.ca.gov/fuels/lcfs/CleanFinalRegOrder112612.pdf*. The incorrect publication date was provided, and is corrected to 2012. There was no 2017 adoption version of the LCFS Regulation.
   - *"Approved Innovative Crude Oil Applications." Website. Available: https://www.arb.ca.gov/fuels/lcfs/crude-oil/innovative-crude/approved_innovative_crude.htm. Accessed: February 23, 2018.* The reference has been clarified to include: CARB Website (Updated September 27, 2016).
   - *Code of Federal Regulations (CFR), Title 40, Part 146.82(a)(3). Available: https://www.ecfr.gov/cgi-bin/text-idx?SID=c88afc711f4da4b6f7527f092c5d5f44&mc=true&node=se40.25.146_182&rgn=div8. Accessed: February 7, 2018.* The reference was mistakenly excluded from in the list of references.
   - *South Coast Air Quality Management District. 2017. California Emissions Estimator Model (CalEEMod) Version 2013.6.2. November 2017. Available: http://www.caleemod.com/.* The version numbers were transposed, and is corrected to 2016.3.2. No version 2013.6.2 exists.

5. Documents referenced in the Notice of Public Availability of Modified Text and Availability of Additional Documents (June 20, 2018)

   - *One Petro – Document Preview, Society of Petroleum Engineers, "Fluid Distribution Model for Structurally Complex Reservoirs in El Carito-Mulata and Santa Bárbara Fields, Venezuela"," 2007. Accessed: May 17, 2018. Available: https://www.onepetro.org/conference-paper/SPE-107948-MS* The author was not provided, and is corrected to include: Carpio, G. et al.
   - *One Petro – Document Preview, Society of Petroleum Engineers, "8500 PSI Gas Injection Project"," 1996. Accessed: May 17, 2018. Available: https://www.onepetro.org/conference-paper/SPE-35603-MS* The author was not provided, and is corrected to include: Rodriguez, E. et al.
   - *One Petro – Document Preview, Society of Petroleum Engineers, "Design of High Angle Wells in the Santa Barbara Field, Eastern Venezuela" 2001. Accessed: May 17, 2018. Available: https://www.onepetro.org/conference-paper/SPE-69450-MS* The author was not provided, and is corrected to include: Flores, D. et al.

6. Documents referenced in the Second Notice of Public Availability of Modified Text and Availability of Additional Documents (August 13, 2018)

   - *N_2O Emissions from Managed Soils, and CO_2 Emissions from Lime and Urea Application, Chapter 11, 2006 IPCC Guidelines for National Greenhouse Gas Inventories vol 4 (Hayama: IGES) IPCC (2006). Available: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/4_Volume4/V4_11_Ch11_N2O&CO2.pdf* The author or editor was not identified, and is corrected to include: De Klein, C. et al.
   - *Carbon Reduction Opportunities in the California Petroleum Industry, NRDC Issue Brief, October 2013. Available: https://www.nrdc.org/sites/default/files/california-petroleum-carbon-reduction-IB.pdf* The author was not identified, and is corrected to include: Law, K. et al.

7. Documents referenced in the Final Supplemental Disclosure Discussion of Oxides of Nitrogen Potentially Caused by the Low Carbon Fuel Standard Regulation (September 17, 2018):

   - *Responses to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Standard and Alternative Diesel Fuel Regulations. CARB, September 14, 2018*. The incorrect date was given. The Final Disclosure and this reference were posted on the same date, September 17, 2018.

III. DOCUMENTS INCORPORATED BY REFERENCE

The regulation adopted by the Executive Officer incorporates by reference the following documents:

- Energy and Environmental Economics, Inc. Avoided Cost Calculator, May 2018, section 95481(a)(10);
- California-modified Greenhouse Gases, Regulated Emissions, and Energy use in Transportation version 3.0 (CA-GREET3.0) model, August 13, 2018 (corrected), section 95481(a)(21) and 95488.3(b);
- Hydrogen Station Capacity Evaluator Version 1.0, August 13, 2018, section 95481(a)(73);
- Oil Production Greenhouse Gas Emissions Estimator Version 2.0, June 20, 2018, section 95481(a)(104);
- CA-GREET3.0 Lookup Table Pathways Technical Support Documentation, August 13, 2018, section 95488.1(b) and 95488.5(e);
- Tier 1 Simplified CI Calculator for Starch and Fiber Ethanol, August 13, 2018, section 95488.3(b)(1);

- Tier 1 Simplified CI Calculator for Sugarcane-derived Ethanol, August 13, 2018 (corrected), section 95488.3(b)(2);
- Tier 1 Simplified CI Calculator for Biodiesel and Renewable Diesel, August 13, 2018 (corrected), section 95488.3(b)(3);
- Tier 1 Simplified CI Calculator for LNG and L-CNG from North American Natural Gas, August 13, 2018, section 95488.3(b)(4);
- Tier 1 Simplified CI Calculator for Biomethane from North American Landfills, August 13, 2018, section 95488.3(b)(5);
- Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Wastewater Sludge, August 13, 2018 (corrected), section 95488.3(b)(6);
- Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure, August 13, 2018 (corrected), section 95488.3(b)(7);
- Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Organic Waste, August 13, 2018 (corrected), section 95488.3(b)(8);
- Tier 1 Simplified CI Calculator Instruction Manual, August 13, 2018, section 95488.6(a)(1)(B);
- Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard, August 13, 2018, section 95490(a);
- ASTM D1250-08 (2013) e1, Standard Guide for Use of the Petroleum Measurement Tables, ASTM D1250-08, reapproved 2013, sections 95491(d)(1)(B)2.b., 95491(d)(1)(B)3;
- American Petroleum Institute (API) Manual of Petroleum Measurement Standards Chapter 11 – Physical Properties Data, May 2004, section 95491(d)(1)(B)3; and
- API Technical Data Book – Petroleum Refining Chapter 6 – Density (Sixth Edition, April 1997), section 95491(d)(3)(B)3.

These documents were incorporated by reference because it would be cumbersome, unduly expensive, and otherwise impractical to publish them in the California Code of Regulations. In addition, some of the documents are copyrighted, and cannot be reprinted or distributed without violating the licensing agreements. The documents are lengthy and highly technical test methods and engineering documents that would add unnecessary additional volume to the regulation. Distribution to all recipients of the California Code of Regulations is not needed because the interested audience for these documents is limited to the technical staff at a portion of reporting facilities, most of whom are already familiar with these methods and documents. Also, the incorporated documents were made available by CARB upon request during the rulemaking action and will continue to be available in the future. The documents are also available from college and public libraries, or may be purchased directly from the publishers.

The following models and CCS Protocol originally listed in the Initial Statement of Reasons (ISOR) for incorporation by reference were replaced in the first and second 15-day notice packages with updated models and protocol based on the latest science and stakeholder input. Therefore, the following versions are not incorporated into the regulation as adopted:

- California-modified Greenhouse Gases, Regulated Emissions, and Energy use in Transportation version 3.0 (CA-GREET3.0) model, March 6, 2018, sections 95481(a)(20), 95488.3(b);
- Oil Production Greenhouse gas Emissions Estimator Version 2.0, March 6, 2018, section 95481(a)(93);
- CA-GREET3.0 Lookup Table Pathways Technical Support Documentation, March 6, 2018, sections 95488.1(b), 95488.5(e);
- Tier 1 Simplified CI Calculator for Starch and Corn-Fiber Ethanol, March 6, 2018, section 95488.3(b)(1);
- Tier 1 Simplified CI Calculator for Sugarcane-derived Ethanol, March 6, 2018, section 95488.3(b)(2);
- Tier 1 Simplified CI Calculator for Biodiesel and Renewable Diesel, March 6, 2018, section 95488.3(b)(3);
- Tier 1 Simplified CI Calculator for LNG and L-CNG from North American Natural Gas, March 6, 2018, section 95488.3(b)(4);
- Tier 1 Simplified CI Calculator for Biomethane from North American Landfills, March 6, 2018, section 95488.3(b)(5);
- Tier 1 Simplified CI Calculator Instruction Manual, March 6, 2018, section 95488.6(a)(1)(B); and
- Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard, March 6, 2018, section 95490(a).

These models and protocol have been updated as shown in the list of documents incorporated by reference above.

The following fuel specifications originally listed in the ISOR for incorporation by reference were removed in the first 15-day notice package. Therefore, the following documents are not incorporated into the regulation as adopted:

- ASTM Specification D910-17 (2017), Standard Specification for Aviation Gasolines (section 95481(a), definition for “Aviation Gasoline”);
- ASTM D975-14a, (2014), Specification for Diesel Fuel Oils (definition for “Biomass-based Diesel”);
- ASTM D1655-17 (2017), Standard Specification for Aviation Turbine Fuels (definition for “Conventional Jet Fuel”);

- ASTM D975-14a, (2014), Standard Specification for Diesel Fuel Oils (definition for “Diesel Fuel Blend”);
- ASTM D4806-14 (2014), Standard Specification for Denatured Fuel Ethanol for Blending with Gasolines for Use as Automotive Spark-Ignition Engine Fuel (definition for “E100,” also knows as “Denatured Fuel Ethanol”); and
- ASTM D1835-16, (2016), Standard Specification for Liquefied Petroleum (LP) Gases (definition for “Renewable Propane”).

IV. SUMMARY OF COMMENTS MADE DURING THE 45-DAY COMMENT PERIOD AND AGENCY RESPONSES

Chapter IV of this FSOR contains all comments submitted during the 45-day comment period and the April 27, 2018 Board Hearing that were directed at the proposed amendments or to the procedures followed by CARB in proposing the amendments, together with CARB's responses. The 45-day comment period commenced on March 9, 2018, and ended on April 23, 2018, with additional comments submitted at the April 27, 2018 Board Hearing on the proposed amendments.

CARB received 137 comment letters during the 45-day comment period and 18 comment letters during the Board Hearing. In addition, 54 stakeholders gave oral testimony at the April 27, 2018 Board Hearing. Each comment letter and the transcript of the testimony are responded to in this FSOR. Commenters included representatives from the electricity and natural gas sectors, refining sectors, health and environmental sectors, reporters and verifiers, airlines, and others. To facilitate the use of this document, comments are categorized into sections and are grouped by responses wherever possible.

Table IV-2 below lists the commenters that submitted oral and written comments on the proposed amendments during the 45-day comment period and at the April 27, 2018 Board Hearing, identifies the date and form of their comments, and shows the abbreviation assigned to each.

The individually submitted comment letters for the 45-day, first 15-day, and second 15-day comment periods are available here: https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm

Note that some comments were scanned or otherwise electronically transferred, so they may include minor typographical errors or formatting that is not consistent with the originally submitted comments. However, all content reflects the submitted comments. All originally submitted comments are available here: https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm. The transcript of verbal testimony presented during the first Board Hearing is available here: https://www.arb.ca.gov/board/mt/2018/mt042718.pdf?_ga=2.118956489.1942328084.1531756299-1243162238.1525361489

Comments that address the draft Environmental Analysis are responded to in the "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuels Regulations."

A. List of Commenters

The comment letters were coded by the order and the comment period in which they were received and by the name of the organization or individual commenting. For instance, OP_BDP1_1 is the first comment received during the 45-day comment period, which is a comment sent by Brightline Defense Project. Table IV-1 lists the comment letter codes based on the comment period.

Table IV-1. Comment Letter Codes

Comment Letter Codes	
Comment Code	Comment Period Received
OP, for original proposal	Comments received during the 45-day comment period of the original proposal, March 9 – April 23, 2018
B, for Board hearing written comments	Comments received as written materials during the Board Hearing, April 27, 2018
T, for testimony at the Board Hearing	Comments received as oral testimony at the Board hearing, April 27, 2018
FF, for first fifteen-day changes	Comments received during the first 15-day comment period, June 20-July 6, 2018
SF, for second fifteen-day changes	Comments received during the second 15-day comment period, August 13-30, 2018
SB, for second Board Hearing written comments	Comments received as written materials during the second Board Hearing, September 27, 2018
ST, for testimony at the second Board Hearing	Comments received as oral testimony at the second Board hearing, September 27, 2018

Written comments were received during the 45-day comment period in response to the April 27, 2018 public hearing notice, and written and oral comments were presented at the Board Hearing. Listed below are the organizations and individuals that provided comments during the 45-day comment period:

Table IV-2. List of Commenters During the 45-Day Comment Period

Comment Letter Code	Commenter
OP_BDP1_1	Ivan Jimenez, Brightline Defense Project 45-Day Comment: March 16, 2018
OP_ITM1_2	Steve Jones, ITM Power 45-Day Comment: March 20, 2018
OP_EF1_3	Mark Heisler, EnergyField Solar, Inc. 45-Day Comment: March 20, 2018
OP_CT1_4	Ex-Commercial Banker and Concerned Taxpayer 45-Day Comment: March 26, 2018
OP_ERI1_6	Lauren Taylor, ERI Solutions Inc. 45-Day Comment: March 30, 2018
OP_DANNAR1_7	Gary Dannar, Dannar 45-Day Comment: April 6, 2018
OP_LCA1_8	Stefan Unnasch and Love Goyal, Life Cycle Associates, LLC 45-Day Comment: April 6, 2018

OP_CAF1_9	Patrick J. McDuff, California Fueling 45-Day Comment: April 9, 2018
OP_VB1_10	Victoria Bermudez RN, Victoria Bermudez RN, Consulting 45-Day Comment: April 10, 2018
OP_BICEP1_11	Anne Kelly, Business for Innovative Climate and Energy Policy 45-Day Comment: April 12, 2018
OP_BART1_12	Thomas W. Solomon, Bay Area Rapid Transit District 45-Day Comment: April 12, 2018
OP_JH1_13	Jane Hirshfield 45-Day Comment: April 13, 2018
OP_GCCC1_14	Susan Hovorka, Gulf Coast Carbon Center 45-Day Comment: April 16, 2018
OP_CULTURA1_15	Janelle London, Cultura 45-Day Comment: April 16, 2018
OP_RNGC1_16	Nina Kapoor, Coalition for Renewable Natural Gas 45-Day Comment: April 16, 2018
OP_AJWIOGEN1_17	Brian Foody, Iogen Corporation Chris Hessler, AJW, Inc. 45-Day Comment: April 16, 2018
OP_FHR1_18	Dan Smading, Flint Hills Resources 45-Day Comment: April 17, 2018
OP_BORREGO1_19	Rachel Bird, Borrego Solar Systems, Inc. 45-Day Comment: April 17, 2018
OP_LINDE1_20	Michael Beckmann, Linde 45-Day Comment: April 18, 2018
OP_WSPA1_21	Catherine Reheis-Boyd, Western States Petroleum Association 45-Day Comment: April 18, 2018
OP_ISCC1_22	Norbert Schmitz and Jan Henke, ISCC System 45-Day Comment: April 19, 2018
OP_DELCE1_23	Cathy DeFalco, Lancaster Choice Energy Scott Olson, Direct Energy Business, LLC 45-Day Comment: April 19, 2018
OP_RV1_24	Ramasamy Vasuthewan 45-Day Comment: April 20, 2018
OP_UIC1_25	Steffen Mueller, PhD, University of Illinois at Chicago 45-Day Comment: April 20, 2018
OP_TD1_26	Tom Darlington 45-Day Comment: April 20, 2018
OP_CHRISTIANSON1_27	Kari Buttenhoff, Christianson PLLP 45-Day Comment: April 20, 2018
OP_CSAG1_28	Doug Morton, CSA Group 45-Day Comment: April 20, 2018
OP_NBB1_29	Jennifer Case, California Advanced Biofuel Alliance

	Shelby Neal, National Biodiesel Board 45-Day Comment: April 20, 2018
OP_H2IND1_30	David P. Edwards, PhD, Air Liquide Dr. Shane Stephens, FirstElement Fuel Stephen Ellis, American Honda Motor Co, Inc. Debbie Bakker, Hyundai Kia America Technical Center, Inc. Nitin Natesan, Linde LLC Matthew Forrest, Mercedes-Benz Research & Development North America, Inc. Mikael Sloth, NEL Hydrogen A/S Wayne Leighty, MBA, PhD, Shell New Energies Michael Lord, Toyota Motor North America Joe Gagliano, United Hydrogen Jeff Serfass, California Hydrogen Business Council Brian Goldstein, Energy Independence Now 45-Day Comment: April 20, 2018
OP_3PR1_31	Michael Leone, 3 Phases Renewables 45-Day Comment: April 20, 2018
OP_CCE1_32	Joshua T. Bledsoe, Latham & Watkins LLP on behalf of Carbon Creek Energy 45-Day Comment: April 20, 2018
OP_MBCP1_33	Tom Habashi, Monterey Bay Community Power 45-Day Comment: April 20, 2018
OP_BLUEPLANET1_34	Jim Atkins, Esq., Blue Planet, Ltd. 45-Day Comment: April 20, 2018
OP_CRC1_35	Mike Glavin, California Resources Corporation 45-Day Comment: April 20, 2018
OP_RTE1_36	Dustin Willett, Red Trail Energy LLC 45-Day Comment: April 22, 2018
OP_PU1_37	Mike Newman and Julia Richardson, Parhelion Underwriting Inc. 45-Day Comment: April 23, 2018
OP_LADWP1_38	Mark J. Sedlacek, Los Angeles Department of Water and Power 45-Day Comment: April 23, 2018
OP_AL1_39	David P. Edwards, PhD, Air Liquide Hydrogen Energy, US 45-Day Comment: April 23, 2018
OP_DR1_40	Dennis Rogoza 45-Day Comment: April 23, 2018
OP_ACE1_41	Brian Jennings, American Coalition for Ethanol 45-Day Comment: April 23, 2018
OP_ARPU1_42	Carrie Thompson, Anaheim Public Utilities Tracy Sato, Riverside Public Utilities 45-Day Comment: April 23, 2018
OP_CVAQ1_43	Dolores Barajas-Weller, Central Valley Air Quality Coalition 45-Day Comment: April 23, 2018

OP_JLRNA1_44	Chris Marchand, Jaguar Land Rover North America LLC 45-Day Comment: April 23, 2018
OP_CRF1_45	Lyle Schlyer, Calgren Renewable Fuels 45-Day Comment: April 23, 2018
OP_PROTERRA1_46	Kent Leacock, Proterra, Inc. 45-Day Comment: April 23, 2018
OP_EC1_47	Mary Macpherson, Equilibrium Capital's Wastewater Opportunity Fund 45-Day Comment: April 23, 2018
OP_EDF1_48	Timothy O'Connor, Environmental Defense Fund 45-Day Comment: April 23, 2018
OP_CAC1_49	Kevin Bumen, California Airports Council 45-Day Comment: April 23, 2018
OP_FCE1_50	Paul Fukumoto, FuelCell Energy, Inc 45-Day Comment: April 23, 2018
OP_INNOSPEC1_51	David Jones, Innospec Inc. 45-Day Comment: April 23, 2018
OP_CCA1_52	Bill Magavern, Coalition for Clean Air 45-Day Comment: April 23, 2018
OP_UCS1_53	Jeremy Martin, Ph.D., Union of Concerned Scientists 45-Day Comment: April 23, 2018
OP_AEM1_54	Ronald Koelsch, Ph.D., Advanced Energy Machines 45-Day Comment: April 23, 2018
OP_P661_55	Marla Benyshek, Phillips 66 Company 45-Day Comment: April 23, 2018
OP_DTEBE1_56	Mark Cousino, DTE Biomass Energy 45-Day Comment: April 23, 2018
OP_A4A1_57	Veronica Bradley and Nancy N. Young, Airlines for America 45-Day Comment: April 23, 2018
OP_FORD1_58	Dominic DiCicco, Ford Motor Company 45-Day Comment: April 23, 2018
OP_JPOUS1_59	Jonathan Changus, Northern California Power Agency Bryan Cope, Southern California Public Power Authority Justin Wynne, Braun Blaising Wynne Smith P.C. 45-Day Comment: April 23, 2018
OP_MUREX1_60	Jennifer M. LeRow, Murex LLC 45-Day Comment: April 23, 2018
OP_WSPA2_61	Catherine Reheis-Boyd, Western States Petroleum Association 45-Day Comment: April 23, 2018
OP_MAERSK1_62	Lee Kindberg, PhD, Maersk Line 45-Day Comment: April 23, 2018
OP_OCCIDENTAL1_63	Al Collins, Sr., Occidental Petroleum Corporation 45-Day Comment: April 23, 2018

OP_RPMG1_64	Jessica W. Hoffmann, RPMG, Inc. 45-Day Comment: April 23, 2018
OP_GLASSPOINT1_65	John O'Donnell, GlassPoint Solar, Inc. 45-Day Comment: April 23, 2018
OP_LCA2_66	Stefan Unnasch, Life Cycle Associates, LLC 45-Day Comment: April 23, 2018
OP_ANDEAVOR1_67	Brian McDonald, Andeavor 45-Day Comment: April 23, 2018
OP_LCA3_68	Stefan Unnasch, Life Cycle Associates, LLC 45-Day Comment: April 23, 2018
OP_DGD1_69a	Elizabeth A Hepp, Diamond Alternative Energy LLC 45-Day Comment: April 23, 2018
OP_VALERO1_69b	Elizabeth A Hepp, Valero Companies 45-Day Comment: April 23, 2018
OP_SUNPOWER1_70	Blair G. Swezey, SunPower Corporation 45-Day Comment: April 23, 2018
OP_CIPA1_71	Rock Zierman, California Independent Petroleum Association 45-Day Comment: April 23, 2018
OP_AECA1_72	Michael Boccadoro, Agricultural Energy Consumers Association 45-Day Comment: April 23, 2018
OP_LOVE1_73	Bill Cashmareck, Trillium Transportation Fuels, LLC and Musket Corporation (members of Love companies) 45-Day Comment: April 23, 2018
OP_KAPPA1_74	Charles Woodside, KAAPA Ethanol 45-Day Comment: April 23, 2018
OP_SCG1_75	Kevin Maggay, SoCalGas 45-Day Comment: April 23, 2018
OP_NESTE1_76	Dayne Delahoussaye, Neste 45-Day Comment: April 23, 2018
OP_LANZATECH1_77	Jennifer Holmgren, LanzaTech 45-Day Comment: April 23, 2018
OP_WE1_78	Greg Thompson, White Energy, Inc. 45-Day Comment: April 23, 2018
OP_TESLA1_79	Ken Morgan, Tesla, Inc. 45-Day Comment: April 23, 2018
OP_RFA1_80	Geoff Cooper, Renewable Fuels Association 45-Day Comment: April 23, 2018
OP_NRDC1_81	Simon C. Mui, Natural Resources Defense Council 45-Day Comment: April 23, 2018
OP_POWEREX1_82	Michael Benn, Powerex Corp. 45-Day Comment: April 23, 2018
OP_WM1_83	Kim Kaminski, Waste Management of Oregon, Inc. 45-Day Comment: April 23, 2018

OP_PMSA1_84	Thomas Jelenić, Pacific Merchant Shipping Association 45-Day Comment: April 23, 2018
OP_SMUD1_85	William W. Westerfield, III and Bill Boyce, Sacramento Municipal Utility District 45-Day Comment: April 23, 2018
OP_AMP1_86	Obi Ofoegbu, Amp Americas 45-Day Comment: April 23, 2018
OP_CCSF1_87	James Hendry, City and County of San Francisco, acting through the San Francisco Public Utilities Commission and the San Francisco Municipal Railway 45-Day Comment: April 23, 2018
OP_REG1_88	Curtis Powers and Scott R. Hedderich, Renewable Energy Group, Inc. 45-Day Comment: April 23, 2018
OP_TASKFORCE1_89	Margaret Clark, Low Angeles County Solid Waste Management Committee/Integrated Waste Management Task Force 45-Day Comment: April 23, 2018
OP_CCSF2_90	James Hendry, City and County of San Francisco, acting through the San Francisco Public Utilities Commission and the San Francisco Municipal Railway 45-Day Comment: April 23, 2018
OP_SDGE1_91	Tim Carmichael, San Diego Gas & Electric 45-Day Comment: April 23, 2018
OP_CE1_92	Todd Campbell, Clean Energy Fuels Corporation 45-Day Comment: April 23, 2018
OP_WSPA3_93	Catherine Reheis-Boyd, Western States Petroleum Association 45-Day Comment: April 23, 2018
OP_CASA1_94	Greg Kester, California Association of Sanitation Agencies 45-Day Comment: April 23, 2018
OP_CBL1_95	Scott Hernandez, CBL Markets 45-Day Comment: April 23, 2018
OP_CALETC1_96	Eileen Wenger Tutt, California Electric Transportation Coalition 45-Day Comment: April 23, 2018
OP_ES1_97	David M. McCullough, Eversheds Sutherland (US) LLP 45-Day Comment: April 23, 2018
OP_ARIA1_98	Jay Hopper, Aria Energy 45-Day Comment: April 23, 2018
OP_BAC1_99	Julia A. Levin, Bioenergy Association of California 45-Day Comment: April 23, 2018
OP_CATF1_100	Deepika Nagabhushan, Clean Air Task Force 45-Day Comment: April 23, 2018
OP_ICE1_101	Stephen McComb, ICE Futures U.S., Inc. and ICE Clear

	Europe Ltd. 45-Day Comment: April 23, 2018
OP_AJFP1_102	Graham Noyes, Noyes Law Corporation on behalf of Alternative Jet Fuel Producers 45-Day Comment: April 23, 2018
OP_FULCRUM1_103	Ted Kniesche, Fulcrum BioEnergy, Inc. 45-Day Comment: April 23, 2018
OP_SK1_104	Graham Noyes, Noyes Law Corporation on behalf of Safety-Kleen 45-Day Comment: April 23, 2018
OP_LCFC1_105	Graham Noyes, Low Carbon Fuels Coalition 45-Day Comment: April 23, 2018
OP_CCSPD1_106	Al Collins, Occidental Petroleum Corporation Paul J. Deiro, California Resources Corporation Tim Ebben, Shell S. Julio Friedmann, Carbon Wrangler, LLC Susan D. Hovorka, University of Texas at Austin Ralph J. Moran, BP America Eric Mork, EBR Development, LLC Deepika Nagabhushan, Clean Air Task Force Brad Page, Global Carbon Capture and Storage Institute Bob Perciasepe, Center for Climate and Energy Solutions Henry T Perea, Chevron Corporation George Peridas, Natural Resources Defense Council Rich Powell, ClearPath Foundation Greg Thompson, White Energy Tom Willis, Conestoga Energy Partners, LLC 45-Day Comment: April 23, 2018
OP_COALITION1_107	Ryan Schuchard, CALSTART John Shears, Center for Energy Efficiency and Renewable Technologies Carol Lee Rawn, Ceres Don Scott, National Biodiesel Board Colin Murphy, NextGen California Tom Koehler, Pacific Ethanol, Inc. Nina Kapoor, Renewable Natural Gas Coalition Heidi Sickler, Silicon Valley Leadership Group Jeremy Martin, Sr., Union of Concerned Scientists 45-Day Comment: April 23, 2018
OP_SCE1_108	Michael Backstrom, Southern California Edison 45-Day Comment: April 23, 2018
OP_CAPA1_109	Tim Schott, California Association of Port Authorities 45-Day Comment: April 23, 2018
OP_LW1_110	Robert A. Wyman, Latham & Watkins LLP 45-Day Comment: April 23, 2018
OP_SREC1_111	Steven Eisenberg, SRECTrade, Inc. 45-Day Comment: April 23, 2018

OP_CHEVRON1_112	Nick Economides, Chevron 45-Day Comment: April 23, 2018
OP_HMO1_113	Barbara Sattler, Alliance of Nurses for Healthy Environments Kris Calvin, American Academy of Pediatrics – California Soma Wali, American College of Physicians – CA Services Chapter Bonnie Holmes-Gen, American Lung Association in California Dr. Scott Takahashi, Asthma Coalition of Los Angeles County David LeDuc, Bonnie J. Addario Lunch Cancer Foundation Janet Nudelman, Breast Cancer Prevention Partners Justin Malan, California Conference of Directors of Environmental Health Ken Cutler, California Conference of Local Health Officers Kimberly Chen, California Pan-Ethnic Health Network Adele Amodeo, California Public Health Association – North Phillipe Montgrain, California Thoracic Society Kevin Hamilton, Central California Asthma Coalition Rachelle Wenger, Dignity Health Praveen Buddiga, Family Allergy Asthma Clinic (Fresno) Nicole Butler, Fresno Madera Medical Society Robyn Rothman, Health Care Without Harm Fonda Winslow, Kern County Medical Society Lynn Kersey, Maternal and Child Health Access (Los Angeles) Jay Herbrand, Merced Mariposa Asthma Coalition Robert M. Gould, San Francisco Bay Area Chapter Physicians for Social Responsibility Harry Wang, Physicians for Social Responsibility, Sacramento Linda Rudolph, Center for Climate Change and Health Public Health Institute Matthew Marsom, Public Health Institute Joel Ervice, Regional Asthma Management and Prevention San Francisco Asthma Task Force Jim Mangia, St. John's Well Child and Family Center (Los Angeles) 45-Day Comment: April 23, 2018
OP_RCM1_114	Mark Moser, RCM International, LLC 45-Day Comment: April 23, 2018
OP_KERN1_115	Melinda L. Hicks, Kern Oil & Refining Co. 45-Day Comment: April 23, 2018
OP_SEVCG1_116	Neal Reardon, Sonoma Clean Power Authority on behalf of the Smart EV Charging Coalition 45-Day Comment: April 23, 2018
OP_LCA3_117	Stefan Unnasch and Love Goyal, Life Cycle Associates,

	LLC 45-Day Comment: April 23, 2018
OP_CNGVC1_118	Thomas Lawson, California Natural Gas Vehicle Coalition 45-Day Comment: April 23, 2018
OP_SEIA1_119	Rick Umoff, Solar Energy Industries Association 45-Day Comment: April 23, 2018
OP_PGE1_120	Linus Farias, Pacific Gas and Electric Company 45-Day Comment: April 23, 2018
OP_WPGA1_121	Joy Alafia, Western Propane Gas Association 45-Day Comment: April 23, 2018
OP_CHARGEPOINT1_122	Amanda Myers, ChargePoint, Inc. 45-Day Comment: April 23, 2018
OP_NEXTGEN1_124	Colin Murphy, NextGen California 45-Day Comment: April 23, 2018
OP_BP1_125	Ralph J. Moran, BP America, Inc. 45-Day Comment: April 23, 2018
OP_RFVV1_126	Robert F. Van Voorhees, Robert F Van Voorhees PLLC 45-Day Comment: April 23, 2018
OP_UNICA1_127	Elizabeth Farina and Leticia Phillips, Brazilian Sugarcane Industry Association (UNICA) 45-Day Comment: April 24, 2018 (late submission)
OP_CBEA1_128	Julee Malinowski Ball, California Biomass Energy Alliance 45-Day Comment: April 25, 2018 (late submission)
OP_POET1_129	Rachel Kloos, POET 45-Day Comment: April 25, 2018 (late submission)
OP_CALETC2_130	Eileen Tutt, California Electric Transportation Coalition 45-Day Comment: April 25, 2018 (non-web submittal)
OP_KELLIM1_131	Kelli M. 45-Day Comment: April 26, 2018 (non-web submittal)
OP_THURSTON1_132	Jim Thurston 45-Day Comment: April 26, 2018 (non-web submittal)
OP_GRIFFITH1_133	Mary Griffith 45-Day Comment: April 26, 2018 (non-web submittal)
OP_CITIZEN1_134	Citizen 45-Day Comment: April 26, 2018 (non-web submittal)
OP_ENERKEM1_135	Marie-Helene Labrie, Enerkem 45-Day Comment: April 20, 2018
OP_COLTURA1_136	Janelle London, Coltura 45-Day Comment: April 27, 2018 (late submission)
OP_MENLO1_137	Diane Bailey, Menlo Spark 45-Day Comment: April 26, 2018 (late submission)
OP_GEVO1_138	Karen O'Brien, Gevo 45-Day Comment: April 12, 2018

OP_CHBC1_139	Emanuel Wagner, California Hydrogen Business Council 45-Day Comment: April 19, 2018
OP_LCA4_140	Stefan Unnasch and Love Goyal, Life Cycle Associates, LLC 45-Day Comment: May 9, 2018 (late submission)
OP_ODOEQ1_141	Bill Peters, Oregon Department of Environmental Quality 45-Day Comment: May 10, 2018 (late submission)
OP_NCPASCPPA1_142	Randy S. Howard, Northern California Power Agency Michael S. Webster, Southern California Public Power Authority 45-Day Comment: May 18, 2018 (late submission)
B_AJFP2_B1	Graham Noyes, Noyes Law Corporation on behalf of Alternative Jet Fuel Producers Board Hearing Comment: April 27, 2018
B_UNICA2_B2	Elizabeth Farina and Leticia Phillips, Brazilian Sugarcane Industry Association (UNICA) Board Hearing Comment: April 27, 2018
B_POET2_B3	Jeffrey Lautt, POET Board Hearing Comment: April 27, 2018
B_GROWTHENERGY1_B4	John P. Kinsey, Wanger Jones Helsley PC on behalf of Growth Energy Board Hearing Comment: April 27, 2018
B_ECOENGINEERS1_B5	John Sens, EcoEngineers Board Hearing Comment: April 27, 2018
B_CALSTART1_B6	Ryan Schuchard, CALSTART Board Hearing Comment: April 27, 2018
B_STI1_B7	Douglas Eisinger, Sonoma Technology, Inc. Board Hearing Comment: April 27, 2018
B_UCLA1_B8	Sean Hecht, Emmett Institute on Climate Change Board Hearing Comment: April 27, 2018
B_CIS1_B9	Daniel Sanchez, Carnegie Institution for Science Board Hearing Comment: April 27, 2018
B_SEVCG2_B10	Neal Reardon, Sonoma Clean Power Authority on behalf of the Smart EV Charging Coalition Board Hearing Comment: April 27, 2018
B_EIN1_B11	Brian Goldstein, Energy Independence Now Board Hearing Comment: April 27, 2018
B_UNITED1_B12	Aaron Robinson, United Airlines Board Hearing Comment: April 27, 2018
B_ALTAIR1_B13	Bryan Sherbacow, AltAir Paramount Board Hearing Comment: April 27, 2018
B_CATF2_B14	Deepika Nagabhushan, Clean Air Task Force Board Hearing Comment: April 27, 2018
B_CCSPD2_B15	Al Collins, Occidental Petroleum Corporation Paul J. Deiro, California Resources Corporation Tim Ebben, Shell

	S. Julio Friedmann, Carbon Wrangler, LLC Susan D. Hovorka, University of Texas at Austin Ralph J. Moran, BP America Eric Mork, EBR Development, LLC Deepika Nagabhushan, Clean Air Task Force Brad Page, Global Carbon Capture and Storage Institute Bob Perciasepe, Center for Climate and Energy Solutions Henry T Perea, Chevron Corporation George Peridas, Natural Resources Defense Council Rich Powell, ClearPath Foundation Greg Thompson, White Energy Tom Willis, Conestoga Energy Partners, LLC Board Hearing Comment: April 27, 2018
B_EMRE1_B16	Keri Richardson Bevel, Element Markets Renewable Energy, LLC Board Hearing Comment: April 27, 2018
B_GROUP1_B17	Jason Barbose on behalf of group Board Hearing Comment: April 27, 2018
B_SFO1_B18	Ivar C. Satero, San Francisco International Airport Board Hearing Comment: April 27, 2018
T_CAPCOA1_T1	Alan Abbs, CAPCOA Oral Testimony: April 27, 2018
T_AJWIOGEN2_T2	Mary Solecki, AJW on behalf of AJW and IOGEN Oral Testimony: April 27, 2018
T_RFA2_T3	Geoff Cooper, Renewable Fuels Association Oral Testimony: April 27, 2018
T_BAC2_T4	Julia Levin, Bioenergy Association of California Oral Testimony: April 27, 2018
T_CE2_T5	Brandon Price, Clean Energy Oral Testimony: April 27, 2018
T_AJFP3_T6	Graham Noyes, Noyes Law Corporation on behalf of Alternative Jet Fuel Producers Oral Testimony: April 27, 2018
T_OCCIDENTAL2_T7	Al Collins, Occidental Petroleum Corporation Oral Testimony: April 27, 2018
T_CHARGEPOINT2_T8	Amanda Meyers, ChargePoint Oral Testimony: April 27, 2018
T_CASA2_T9	Sarah Deslauriers, California Association of Sanitation Agencies Oral Testimony: April 27, 2018
T_ANDEAVOR2_T10	Brian McDonald, Andeavor Oral Testimony: April 27, 2018
T_NESTE2_T11	Dayne Delahoussaye, Neste Oral Testimony: April 27, 2018
T_CCA2_T12	Rocky Rushing, Coalition for Clean Air Oral Testimony: April 27, 2018

T_CALSTART2_T13	Ryan Schuchard, CALSTART Oral Testimony: April 27, 2018
T_CERES1_T14	Justin Malan, Ceres Oral Testimony: April 27, 2018
T_HMO2_T15	Will Barrett, American Lung Association on behalf of 26 Health Organizations Oral Testimony: April 27, 2018
T_REG2_T16	Scott Hedderich, Renewable Energy Group Oral Testimony: April 27, 2018
T_SFO2_T17	Erin Cooke, San Francisco International Airport Oral Testimony: April 27, 2018
T_CEP1_T18	Dave Rubenstein, California Ethanol & Power Oral Testimony: April 27, 2018
T_NRDC2_T19	Simon Mui, Natural Resources Defense Coucil Oral Testimony: April 27, 2018
T_SCG2_T20	Kevin Maggay, SoCalGas Oral Testimony: April 27, 2018
T_CAC2_T21	Sarah Johnson, California Airports Council Oral Testimony: April 27, 2018
T_GLB1_T22	Dwight Hanson, Green Lane Biogas Oral Testimony: April 27, 2018
T_NBBCABA2_T23	Louie Brown, National Biodiesel Board and California Advanced Biofuels Alliance Oral Testimony: April 27, 2018
T_RPMG2_T24	Jon Costantino, Renewable Products Marketing Group Oral Testimony: April 27, 2018
T_NEXTGEN2_T25	Colin Murphy, NextGen California Oral Testimony: April 27, 2018
T_TESLA2_T26	Ken Morgan, Tesla Oral Testimony: April 27, 2018
T_WPGA2_T27	Joy Alafia, Western Propane Gas Association Oral Testimony: April 27, 2018
T_SCPA1_T28	Brian Biering, Sonoma Clean Power Authority Oral Testimony: April 27, 2018
T_LLNL1_T29	Steve Bohlen, Lawrence Livermore National Laboratory Oral Testimony: April 27, 2018
T_EIN2_T30	Ruben Aronin, Energy Independence Now Oral Testimony: April 27, 2018
T_CE3_T31	Ryan Kenny, Clean Energy Oral Testimony: April 27, 2018
T_CNGVC2_T32	Thomas Lawson, California Natural Gas Vehicle Coalition Oral Testimony: April 27, 2018
T_CHEVRON2_T33	Julia Bussey, Chevron Oral Testimony: April 27, 2018

T_WE2_T34	Brian Steenhard, White Energy Oral Testimony: April 27, 2018
T_CEC1_T35	Jane Berner, California Energy Commission Oral Testimony: April 27, 2018
T_UAA4A1_T36	Melinda Yee Franklin, United Airlines and Airlines 4 America Oral Testimony: April 27, 2018
T_CHBC2_T37	Jeff Reed and Emanuel Wagner, California Hydrogen Business Council Dave Edwards, Air Liquide Michael Lord, Toyota Motor North America Robert Bienenfeld, American Honda Shane Stephens, First Element Fuel Elan Bond, NEL Joe Gagliano, United Hydrogen Wayne Leighty, Shell Oral Testimony: April 27, 2018
T_LCA5_T38	Stefan Unnasch, Life Cycle Associates Oral Testimony: April 27, 2018
T_CONESTOGA1_T39	Tony Brunello, Conestoga Energy Oral Testimony: April 27, 2018
T_ALTAIR2_T40	Bryan Sherbacow, AltAir Paramount (part of World Energy) Oral Testimony: April 27, 2018
T_CATF3_T41	Deepika Nagabhushan, Clean Air Task Force Oral Testimony: April 27, 2018
T_PE1_T42	Tom Koehler, Pacific Ethanol Oral Testimony: April 27, 2018
T_RNGC2_T43	Nina Kapoor, Coalition for Renewable Natural Gas Oral Testimony: April 27, 2018
T_AECA2_T44	Michael Boccadoro, Agricultural Energy Consumers Association Oral Testimony: April 27, 2018
T_LBNL1_T45	Curtis Oldenburg, Lawrence Berkeley National Laboratory Oral Testimony: April 27, 2018
T_CVAQ2_T46	Genevieve Gale, Central Valley Air Quality Coalition Oral Testimony: April 27, 2018
T_UTILITIES1_T47	Eileen Tutt, California Electric Transportation Coalition on behalf of Southern California Public Power Authority, Northern California Power Authority, PG&E, Edison, SDG&E, SMUD, LADWP, and CalETC Oral Testimony: April 27, 2018
T_WSPA4_T48	Catherine Reheis-Boyd, Western States Petroleum Association Oral Testimony: April 27, 2018
T_GM1_T49	Jamie Hall, General Motors Oral Testimony: April 27, 2018

T_SHELL1_T50	Michael Carr, Shell Oral Testimony: April 27, 2018
T_GCCSI1_T51	Pete Montgomery, Global CCS Institute Oral Testimony: April 27, 2018
T_CCC1_T52	Evan Edgar, California Compost Coalition Oral Testimony: April 27, 2018
T_UCS2_T53	Jason Barbose, Union of Concerned Scientists Oral Testimony: April 27, 2018
T_AAM1_T54	Steve Douglas, Alliance of Automotive Manufacturers Oral Testimony: April 27, 2018

B. General Comments in Support of the Proposed Amendments

B-1. Multiple Comments: *General Support for the Proposed Amendments*

Comment: EnergyField appreciates the work done by CARB on the 2018 proposed amendments to the LCFS, as well as the opportunity to publicly comment on the same. We support the goals of the amendments and particularly applaud the changes to opt-in rules regarding crude produced using innovative methods. (EF1_3-1)

Comment: DANNAR strongly supports the LCFS and efforts to encourage the use and production of cleaner low-carbon fuels in California. (DANNAR1_7-1)

Comment: We applaud ARB staff for recommending the extension of the program through 2030. The LCFS has a strong track record of economic, environmental, and public health success in California and through this success has garnered the support of a large group of stakeholders including environmental, public health, environmental justice, and business groups as well as fuel producers. Since 2011, the LCFS has helped avoid the emission of 33 million tons of carbon pollution and use of almost 10 billion gallons of gasoline. The program has also helped avoid over $1 billion in public health costs and has helped reduce local, toxic air pollution in communities through the state. In addition, there's strong evidence that the LCFS drives economic opportunity. In the last seven years $2 billion in low carbon fuel investment has flowed into California helping to create over 300 clean transportation companies that employ 20,000 workers across the state. And by diversifying fuel supplies and lessening dependence on imported oil, the LCFS has helped reduce fuel price volatility, helping California businesses and fleet managers to plan and minimize costs. (BICEP1_11-2)

Comment: While BART supports many of the proposed changes to the LCFS Regulation, it believes that the draft amendments to the LCFS Regulation should be clarified in several respects.

…

Again, BART fully supports CARB's goal of reducing California's GHG emissions, and to this end appreciates CARB's efforts to continue to improve the LCFS Regulation. (BART1_12-5)

Comment: As a member of the public with a vested interest in a viable planet, I applaud California's leadership in setting fuel standard goals that will bring us, if possible, back from the precipice of climate-change tipping point.

I ask the Board to do everything within their power to lower emissions, increase efficiency, and preserve/restore the best possible air quality for California, the country, and the planet. (JH1_13-1)

Comment: We write on behalf of AJW and Iogen to express our support for the LCFS program and provide specific comments on the proposal presented by your staff. As a direct result of the LCFS, California is leading the world in the effort to establish commercially-viable fuel options that will contribute to lower greenhouse gas (GHG) emissions from transportation. We encourage you to continue the LCFS and strengthen the program in ways that will accelerate investments in this sector for years to come. (AJWIOGEN1_17-1)

Comment: After a review of the changes proposed by the ARB for the LCFS program, we would like to express our support for the modifications and considerations made by ARB staff.

…

<u>LCE and Direct Energy Support the Proposed Changes</u>

After a review of the changes proposed by the ARB for the LCFS program, we would like to express our support for the modifications and considerations made by ARB staff. These changes will provide clearer market price information, enhance market liquidity, and provide further incentives for the development of renewable energy projects throughout California. (DELCE1_23-1)

Comment: We continue to appreciate the tremendous job you and CARB staff do on behalf of the clean fuels industry and all Californians. It has been a pleasure to work with you over the years. (NBBCABA1_29-1)

Comment: LADWP reaffirms its strong support of the LCFS program and its role in achieving the substantial greenhouse gas (GHG) emissions reductions goals of AB 32 and SB 32. (LADWP1_38-1)

Comment: LADWP supports ARB staff proposal outlined in the August 7th concept paper for reporters of electricity, hydrogen, fossil natural gas and fossil propane fueling using the Lookup Table pathways. (LADWP1_38-11)

Comment: We congratulate CARB on the fact that as of the third quarter of 2017, the LCFS has exceeded expectations in achieving a reduction of 3.7 percent in the average CI of motor fuels compared to the 2010 baseline. Thanks to the LCFS, several ACE-member biofuel companies hold pathways to produce low carbon fuel for the California market. As such, we strongly support the LCFS and want to help CARB continue accomplishing the goal of decarbonizing fuels used in the state. Indeed, our

members are proud ethanol stands out as contributing more toward LCFS success so far than any other low carbon fuel. (ACE1_41-1)

Comment: This program demonstrates California's leadership in the fight for a better environment. We are committed to doing our part by developing, funding and operating innovative projects to help achieve LCFS goals.

Overall the proposed 2018 amendments to the LCFS regulations are well thought out and appropriate. (CRF1_45-1)

Comment: Proterra strongly supports the LCFS and efforts to encourage the use and production of cleaner low-carbon fuels in California. (PROTERRA1_46-1)

Comment: As a direct result of the LCFS, California is leading the world in the effort to establish commercially-viable fuel options that will contribute to lower greenhouse gas (GHG) emissions from transportation. We encourage you to continue the LCFS and strengthen the program in ways that will accelerate investments in this sector for years to come. (EC1_47-1)

Comment: Please accept these comments from Environmental Defense Fund in support of the continued implementation and appropriate modification of the California Low Carbon Fuel Standard (LCFS) regulation. As a direct result of the LCFS working in concert with other state policies on transportation fuels and vehicles, California is leading the world in the effort to establish commercially-viable fuel options that will contribute to lower greenhouse gas (GHG) emissions from transportation. We encourage the California Air Resources Board (CARB) to continue the LCFS, extend its reach and breadth, and strengthen the program in ways that will accelerate investments in this sector for years to come. (EDF1_48-1)

Comment: We support amending the LCFS with higher targets through 2030. The LCFS is already helping to reduce greenhouse gas emissions and air pollution by starting the process of diversifying our transportation fuel mix, and needs to be ramped up to maximize progress toward that goal. The LCFS increases the use of alternative vehicle fuels like electricity, hydrogen, renewable diesel and renewable methane, reducing our reliance on petroleum. (CCA1_52-1)

Comment: On behalf of our more than 75,000 supporters in California the Union of Concerned Scientists strongly supports the 2018 Low Carbon Fuel Standard (LCFS) amendments proposed in the Initial Statement of Reasons. (UCS1_53-1)

Comment: And we'd certainly like to commend staff for developing the proposal to extend the program to 2030. The proposed amendments really build on the program's success and set it up well to increase in ambition over the coming decade. (UCS2_T53-1)

Comment: Advanced Energy Machines strongly supports the LCFS and efforts to encourage the use and production of cleaner low-carbon fuels. (AEM1_54-1)

Comment: DTEBE appreciates the work done by CARB to strengthen the Low Carbon Fuel Standard Program (LCFS) and we support many of the proposed amendments. (DTEBE1_56-1)

Comment: The Joint POUs support the Low Carbon Fuel Standard ("LCFS") program as an essential and effective strategy for diversifying California's transportation fuels and significantly reducing greenhouse gas ("GHG") emissions from the transportation sector in furtherance of the state's climate change goals. (JPOUS1_59-1)

Comment: Since the program's inception over a decade ago, we have supported California's clean transportation fuel policy, including the LCFS through focus on innovation and its real-world impacts. (RPMG1_64-1)

Comment: One, we support the program, its extension; and highlight some of the notes that have been already -- Julia Levin, Geoff Cooper, Simon Mui. They all talked about the benefits of alternative fuel, the length at which liquid and combustion gases will be used in transportation over the next 10 or 15 or 20 or 30 years. And so ethanol will play an important role. There's a lot of benefits that can still be provided by biofuels. We want to just highlight the support. (RPMG2_T24-1)

Comment: We support CARB's continuing efforts to improve the LCFS program in general, and the Innovative Crude provisions specifically. (GLASSPOINT1_65-1)

Comment: The proposed regulation and regulatory packet are important programmatic changes that will impact CIPA members for years to come. (CIPA1_71-1)

Comment: Neste supports California's commitment to reducing the greenhouse gas emissions associated with transportation fuel and has incorporated this demand for low-carbon fuels into our business plans. Specifically, Neste has delivered, and plans to continue to deliver, commercial volumes of renewable hydrocarbon diesel (NesteMY Renewable Diesel), which qualifies as a low carbon fuel, to numerous customers in California. Additionally, Neste is commercializing renewable jet fuel (NesteMY Renewable Jet) and looks forward to bringing growing volumes to California's airports. (NESTE1_76-1)

Comment: First off, he [*sic*] think this is a very impressive program and we're very supportive of this program. And we think it's important as a market participant to come in and express that appreciation for the staff, for the Board for putting this program forward and continuing to move it forward.

So we do support the post-2020 amendments that exist; (NESTE2_T11-1)

Comment: Overall we agree with the approach ARB has taken with respect to the proposed regulatory changes to the LCFS. We would like to propose a few modifications to further strengthen the proposed regulation. (LANZATECH1_77-2)

Comment: The LCFS regulation is an important tool to reduce carbon emissions in the state's transportation sector and to promote sustainable technology deployment. Within

the LCFS, the electricity pathway has great potential to dramatically impact the adoption of Electric Vehicles (EVs) and encourage the use of solar energy. To realize this potential, we recommend CARB consider several modifications to the regulation in this rulemaking.

…

Tesla appreciates the opportunity to provide comments, and we believe in the potential of this program to dramatically accelerate California's transition to sustainable, zero-emission transportation. We share CARB's vision for a sustainable future and look forward to continuing to collaborate with staff to achieve the goals of the program. (TESLA1_79-1)

Comment: As CARB now considers expanding the LCFS through 2030 and ramping up the required fuel carbon intensity reduction to 20% below 2010 levels, we want to express our support for actions that can help facilitate achievement of future LCFS goals by accelerating and maximizing the decarbonization of remaining liquid transportation fuels. Indeed, RFA's support was commemorated in a recent letter to Gov. Brown and Chair Nichols, included as Attachment A to these comments.

…

As described elsewhere in these comments, domestically produced ethanol has played an important role in the success of the LCFS to date. We look forward to working with CARB to ensure the full potential of ethanol to help decarbonize the state's remaining liquid fuels can be realized. To that end, we ask that CARB consider the following actions that would enable ethanol to make even greater contributions to the achieving the goals of the LCFS moving forward.

…

As the ARB now considers expanding the LCFS through 2030 and ramping up the required fuel carbon intensity reduction to 20% below 2010 levels, we want to express our support for actions that can help facilitate achievement of future LCFS goals by accelerating and maximizing the decarbonization of remaining liquid transportation fuels. (RFA1_80-1)

Comment: As the ARB now considers adoption of more ambitious LCFS targets, I am here to express our support for the program and for actions that will support achievement of the long-term CI reduction goals under consideration today. (RFA2_T3-1)

Comment: Thank you for your commitment to cleaner, healthier air for all Californians and for your international leadership in protecting current and future generations from the impacts of climate pollution. NRDC appreciates the work of the Board and staff to extend the Low Carbon Fuel Standard (LCFS), a key program to meet the state's carbon pollution reduction requirements under AB 32 and SB32. (NRDC1_81-1)

Comment: In closing, we urge ARB continue its decade long support of the LCFS and extend it into the next decade. Climate policy solutions for the transportation sector are needed in California, in other states, across the nation, and around the world. ARB must continue its longstanding leadership role by sending a strong signal that California will move forward – together with other subnational and national jurisdictions. (NRDC1_81-20)

Comment: The LCFS is by far one of the most important measures to help us meet SB 32 as well as the current AB 32. And we know that it's pulling more weight than ever before, and we need the program. Today the program has helped the State avoid over 33 million metric tons of carbon pollution, which is equivalent to about 7 million cars off the road for a year.

It's helped bring in additional alternative low-carbon fuel use. Since the program left the station in 2011, alternative fuel use has increased by 64 percent in the State.

We heard from a number of stakeholders in the types of projects. I'll just -- that have been enabled by the Low Carbon Fuel Standard. I'll cite the ability for now transit agencies to move towards cleaner buses, including transit agencies like Foothill Transit and Antelope Valley Transit recently purchasing electric buses. Even the petroleum industry is moving to cut their carbon pollution under this program.

The world -- North America's largest renewable project was announced to be built in Kern County last year, and 850 megawatt solar ray that will displace the combustion of natural gas in Kern County, helping reduce criteria pollutants and GHGs.

All told, the investments are amounting to an increase of about $2 billion in California, and that will grow together with public health benefits that we're seeing from the program. (NRDC2_T19-1a)

Comment: The Sacramento Municipal Utility District (SMUD) appreciates the last two years of work by dedicated Board staff that has led to the Proposed Amendments to the Low Carbon Fuel Standard (LCFS) Regulation (Proposed Amendments). SMUD supports the Proposed Amendments in large part and continues to implement innovative programs to move the economy of the Sacramento region toward a zero-emission transportation future. (SMUD1_85-1)

Comment: We appreciate the time and energy CARB staff have committed to this rulemaking process over the past few years. We are appreciate the countless public workshops and discussion we have had with CARB staff. We are hopeful that this updated rule-making will continue to set the standard for all other low carbon/clean fuel policies around the world. (REG1_88-1)

Comment: Although many important steps have been taken towards meeting California's greenhouse gas ("GHG") reduction goals, SDG&E believes that a continued effort is needed.

SDG&E strongly supports efforts for the Low Carbon Fuel Standard ("LCFS"). SDG&E believes that LCFS has been successful in reducing the carbon intensity of California's transportation fuel and is an essential element to diversity of transportation fuels, and reducing the emissions from carbon-based fuels. (SDGE1_91-1)

Comment: Clean Energy remains a committed supporter of California's LCFS program and appreciates ARB Staff's diligent work and collaboration with industry stakeholders throughout the regulatory amendment process. (CE1_92-1)

Comment: Clean Energy remains a main supporter of the LCFS and we support the staff's proposed amendments that have been put forth today. (CE2_T5-1)

Comment: I'm Ryan Kenny with Clean Energy, and we are proud to support the LCFS. We've been original supporter since the beginning. (CE3_T31-1)

Comment: CBL is excited to support the LCFS and more broadly transportation electrification in North America. (CBL1_95-5)

Comment: CalETC appreciates this opportunity to SUPPORT the Low Carbon Fuel Standard regulation and provide feedback for CARB Board member consideration. This letter largely supports the proposed draft regulation order and provides some suggested modifications for consideration. We also appreciate the tremendous effort and accessibility of CARB staff during the extensive public process leading up to this hearing.

…

CalETC supports the LCFS, a program that has been successful in reducing the carbon intensity of California's transportation fuel. Given the near-total dependence on oil in the transportation fuels sector, the LCFS is essential to both diversify the transportation fuels sector and reduce emissions from carbon-based fuel.

…

CalETC largely supports the proposed amendments to the LCFS (also referred to as draft regulation order). (CALETC1_96-1)

Comment: As a company participating in the LCFS program today as a credit generator, we are deeply committed to supporting California's clean air and climate goals and would like to provide the following comments to improve the effectiveness of the LCFS program. With these changes, we believe the program will dramatically enhance its impact on the growth of zero-emission transportation in California. (ARIA1_98-1)

Comment: BAC supports many of the proposed changes, but… (BAC1_99-1)

Comment: Safety-Kleen is supportive of ARB's plans to facilitate LCFS credit generation through co-processing. The LCFS has proven to be an effective,

market-based program that has driven the development and expanded the supply of low carbon fuels in California. By developing rules that facilitate co-processing, ARB will further expand the supply of less carbon-intense fuels and facilitate attainment of California's greenhouse gas ("GHG") reduction policies. (SK1_104-1)

Comment: The LCFC is strongly supportive of the program extension, the additional carbon intensity reductions, and the robust and transparent rulemaking that Air Resource Board ("ARB") staff have conducted over the past two years. The LCFC has been a steady participant in the rulemaking since its inception, and has kept its members updated about activities and developments throughout the process. (LCFC1_105-1)

Comment: Longtime supporters of the Low Carbon Fuel Standard, we see the standard as a critical policy in the state's climate change-fighting toolbox. We urge you to move forward in 2018 with strengthening the LCFS and extending it to 2030 to meet our SB32 goals.

To date, the LCFS has delivered impressive benefits to California:

- Since its inception in 2011 and through Q3 2017, the LCFS has helped the state avoid about 33 million metric tons of carbon emissions, and almost 10 billion gallons of petroleum.[1]
  [1] Calculated from California Air Resources Board, *2017 LCFS Reporting Tool, Quarterly Data Summary, Report No. 3,* https://www.arb.ca.gov/fuels/lcfs/dashboard/quarterlysummary/20180131_q3datasummary.pdf
- In Q3 2017, the most recent quarter for which LCFS data are available, the carbon intensity of all transportation fuels used in the state decreased 3.7 percent relative to a 2010 baseline.[2]
  [2] California Air Resources Board, draft LCFS ISOR Executive Summary, February 20, 2018, https://www.arb.ca.gov/fuels/lcfs/2018-0220_preliminary-draft-lcfs-staffreport_es-ch1-2.pdf
- Since its inception, the LCFS has increased investment in the clean fuels market—including production and distribution—by an estimated $2 billion, helping lead to alternative fuel use increasing by 64 percent.[3] The LCFS is spurring investments across the clean fuel supply chain.
  [3] Calculated from ARB's quarterly compliance data which tracks industry performance.
- The LCFS, when combined with other strategies like carbon pricing, is delivering health benefits that will continue to grow as the use of cleaner fuels and cleaner vehicles increase due to these programs.
- The LCFS credit program helps make the use of clean, low carbon fuels economically viable for fleets, such as local transit operators. And with more diverse fuel choices, more efficient cars and less-frequent trips to the pump, Californians' annual fuel costs are declining thanks to our climate and energy policies.

Clearly, the LCFS is doing much good for our state and is working as intended. The following comments both reflect on the value of the LCFS as a performance-based

policy framework that serves as a model for other jurisdictions and outline our views on several policy provisions proposed by staff in the Initial Statement of Reasons (ISOR) issued March 6, 2018. (COALITION1_107-1)

Comment: Southern California Edison (SCE) appreciates this opportunity to comment on the proposed draft regulation order regarding the Low Carbon Fuel Standard (LCFS), and the hard work by CARB staff that went in to this effort.

SCE has long supported the LCFS, since the original signing of the Executive Order.[1] SCE believes that the LCFS is an important component of the State's efforts to diversify the transportation fuels sector and reduce emissions from carbon-based fuel.

1 Executive Order S-1-07

(SCE1_108-1)

Comment: Pacific Gas and Electric Company (PG&E) offers the following comments to the California Air Resources Board (CARB) in support of the proposed amendments to the Low Carbon Fuel Standard (LCFS) regulation. Advancing low-carbon fuels will play a key role in achieving the state's 2030 greenhouse gas emissions reduction targets, and we believe that the increased use of electricity, conventional and renewable natural gas, and hydrogen are critical fuels needed for the success of the LCFS program. (PGE1_120-1)

Comment: The LCFS is a key element of California's climate and clean energy leadership. AB 32 (Chapter 488, Statutes of 2006) began the process of decarbonizing one of the world's largest and most advanced economies. The success of policies such as the LCFS will likely allow California to meet AB 32's goal of returning to 1990 levels of emissions well before the 2020 target date. With the passage of SB 32 (Chapter 249, Statutes of 2016), California has set an ambitious, but achievable, target of reducing emissions 40% below 1990 levels by 2030.

Just as the LCFS was important to the success of AB 32, it will play an even more crucial role as the state works to attain the SB 32 target and set a course for even deeper cuts after 2030. California has achieved most of its emission reductions to date from the electricity sector and is on track to virtually eliminate emissions from power plants by midcentury; now California must rapidly accelerate emission reduction from the transportation sector to meet its 2030 target and longer term climate goals. It is therefore crucial that the program be re-adopted and positioned to achieve the fullest extent of its potential to drive down emissions and support advanced clean energy technologies. (NEXTGEN1_124-1)

Comment: A Strong LCFS Positions California for Success

CARB has an opportunity to build upon many years of success by extending a strong LCFS program through 2030 and building upon the foundation it has laid. California has an opportunity to continue its leadership in climate, clean energy and transportation policy for years to come.

We again thank CARB and the LCFS Program Staff for the opportunity to comment on this critical rulemaking and for their effort, thoughtfulness, transparency and receptiveness to feedback through this process. Their work has produced a strong and set of proposals for the LCFS program and with a few amendments, as discussed in this letter, we are confident that the LCFS can achieve its full potential to deliver cleaner air, innovative technology and sustainable transportation. We look forward to continued engagement on this matter as it continues through the rulemaking process. (NEXTGEN1_124-54)

Comment: For the most part, we agree with their recommendations and the proposed amendments that they've suggested, particularly things like the alternative jet fuel provisions, renewable and smart charge, and carbon capture and sequestration. (NEXTGEN2_T25-1)

Comment: We appreciate and share CARB's goal of improving the effectiveness of the LCFS program. This goal complements the promotion and use of biomass materials, both in the production of renewable electricity and specifically in the use of such electricity as a transportation fuel for electric vehicles.

…

As your staff is aware, the California biomass industry has strongly advocated for inclusion of biomass power in the LCFS. For decades, our members have supplied low carbon electricity to the California grid, and as a result paved the way for carbon reductions in the transportation sector. As an industry, we applaud Governor Brown's aggressive Executive Order, B-48-18, regarding the increased deployment of electric vehicles. Because of the abundance of low carbon intensity electricity in the form of biomass power, we believe that not only can our state achieve that goal, but it can do so using power that has the benefits of a more sustainable form of transportation fuel while promoting rural communities, reducing the risk of forest fires, and improving air quality. (CBEA1_128-1)

Comment: Please extend our Low Carbon Fuel Standard to 2030. (KELLIM1_131-1)

Comment: Please extend California's Low Carbon Fuel Standard! Our planet is at risk!

Please extend California's Low Carbon Fuel Standard to 2030. Our climate is at risk! (THURSTON1_132-1)

Comment: Please tell CA's Air Resources Board to extend California's Low Carbon Fuel Standards to 2030. (GRIFFITH1_133-1)

Comment: Please extend California's Low Carbon Fuel Standard until 2030 or beyond. Please make sure the air, water, food, waterways are clean and pristine. (CITIZEN1_134-1)

Comment: We commend the California Air Resources Board (CARB) for continuing to pursue reductions in the carbon intensity of the transportation fuel pool used in California and believe that the LCFS is an effective and fair tool for achieving this goal. We applaud the proposal to extend the LCFS program targets for the 2020 to 2030 period, which will create the certainty and stability needed to attract investment in low carbon fuels production. (ENERKEM1_135-1)

Comment: On behalf of the Northern California Power Agency (NCPA) and Southern California Public Power Authority (SCPPA), we respectfully submit follow-up comments to the April 27, 2018 CARB Board meeting to reiterate our support for extending the LCFS Program through 2030.

…

As noted in the joint publicly-owned utility comments submitted on April 23, 2018, NCPA and SCPPA support LCFS as an essential strategy for diversifying California's transportation fuels and reducing GHG emissions in furtherance of achieving California's goal of reducing GHG emissions by 40% below 1990 levels by 2030. NCPA and SCPPA also support the Governor's Executive Order B-18-48, establishing a goal of 5 million Zero-Emission Vehicles on California roads by 2030. (NCPASCPPA1_142-1)

Comment: POET lauds the Air Resources Board for its overall goal of combatting climate change, and for certain important changes that CARB is proposing to the Low Carbon Fuel Standard. (POET2_B3-1)

Comment: We believe CARB plays a leadership role in guiding global low-carbon fuel policies, and a successful LCFS program is key to reducing greenhouse gases from the transportation sector. We would like to congratulate CARB on steadfastly maintaining the policy objectives of the LCFS over the past decade and having the vision to take it into the next. Our comments are being provided with the intention of building on LCFS' past successes and helping CARB create a robust program for the future. (ECOENGINEERS1_B5-1)

Comment: Energy Independence Now (EIN), strongly supports the staff recommendation to strengthen and extend the LCFS program through 2030. (EIN1_B11-1)

Comment: Energy Independence Now is the only environmental nonprofit solely dedicated to advancing the hydrogen electric marketplace, and strongly supports the staff recommendation to strengthen and extend the LCFS program; (EIN2_T30-1a)

Comment: We strongly support the transparency, the engagement, the overall regulatory structure, and the specific details of this rule. (AJFP3_T6-1)

Comment: We support the proposal. (CALSTART2_T13-1a)

Comment: The health community has been a vocal and strong supporter of the LCFS over its first decade, both in California and as other states have looked to adopt the program.

The LCFS contributes to cleaner air choices, less pollution on transit corridors, and in freight-impacted communities, and overall spurs a greater shift to a clean air future.

…

And in closing, just wanted to once again state the strong support of the public health medical community for the Low Carbon Fuel Standard as a key driver of cleaning up our transportation fuel sector and moving us to cleaner and healthier zero-emission options. (HMO2_T15-1)

Comment: All I can say is thank you very much to the Board and to the staff, because the LCFS, if that was not in place, there's no way this project that's going to cost $900 million to build would get financed. And it's critical that with long-term financing like that, the extension in the strengthening of the LCFS is absolutely critical, and the work you're doing is terrific. (CEP1_T18-1)

Comment: We are very supportive of the LCFS program. We think it's been very important in reducing carbon emissions and been -- and encouraging the use of low-carbon alternative fuels.

And generally we're a supporter of the amendments… (SCG2_T20-1)

Comment: Sonoma Clean Power strongly supports the proposed amendments to the Low Carbon Fuel Standard. (SPCA1_T28-1)

Comment: Laboratories of the DOE tend to look at these issues very technically and scientifically. And California's leadership is driving transportation sector emissions through policies such as this are to be commended. You're a world leader. And the modifications to the LCFS help you maintain that position. (LLNL2_T29-1)

Comment: We fully support Low Carbon Fuel Standard and its goals and in particular the CCS protocol. (WE2_T34-1)

Comment: We've been supportive of the LCFS since its inception and we are supportive of the extension to 2030. (PE1_T42-1)

Comment: So again, we support this program and we think it can be made better than it is today. (AAM1_T54-2)

Comment: Blue Planet[1] strongly supports the LCFS and efforts to encourage the use and production of cleaner low-carbon fuels in California.

[1] Blue Planet is a California company that has developed a patented process technology that captures carbon dioxide from raw industrial flue gas and permanently sequesters it as construction aggregate, allowing for the world's lowest net CO2 footprint concrete.

(BLUEPLANET1_34-1)

Agency Response: Staff appreciates the commenters' support for the proposed amendments.

B-2. Multiple Comments: *Take Action This Year*

Comment: We urge CARB to take action this year to implement these changes. California has set bold targets for EV adoption, low carbon fuel use and air quality improvements. It will take smart, focused policy to ensure these targets are achieved. The recommendations in this letter represent a significant step in that direction. (BDP1_1-3, CULTURA1_15-3, CVAQ1_43-4, ARIA1_98-4, SEIA1_119-7)

Comment: We urge CARB to take action this year to implement these changes so that California can accelerate progress toward our bold targets for EV adoption, low carbon fuel use and air quality improvements. (CCA1_52-6).

Comment: We urge CARB to take action this year to implement these changes. California has set bold targets for EV adoption, low carbon fuel use and air quality improvements, and we hope with California's LCFS amendments and achievements other West Coast states will follow and replicate California's model. It will take smart, focused policy to ensure these targets are achieved. The recommendations in this letter represent a significant step in that direction. (WM1_83-3)

Comment: The LCFS must play an even more important role in the next decade of California's climate policy. While California has taken great steps to reduce its emissions of carbon pollution, more is necessary if we are to bring our economy onto a trajectory compatible with preventing catastrophic climate change, as called for in the Paris Accord and the Under 2 MoU. Transportation represents the largest source of emissions in California, with 39% of total in-state anthropogenic emissions coming from vehicles and almost 10% more resulting from the production of transportation fuels.[5] On-road transportation (passenger vehicles and freight trucks) consume the overwhelming majority of transportation fuel. State and Federal policies are working to make vehicles more efficient and provide alternatives to conventional on-road transportation, but these measures cannot, by themselves, deliver sufficient reductions from the transportation sector to meet SB 32 goals. We must decarbonize the fuels which supply our transportation system in addition to consuming less of them.

[5] https://www.arb.ca.gov/cc/inventory/data/data.htm

(NEXTGEN1_124-3a)

Comment: We thank ARB for its continued efforts to decarbonize California's fuel supply and urge the Board to adopt the proposed amendments to the LCFS that include AJF as an opt-in fuel starting January 1, 2019. (SFO1_B18-3)

Comment: And finally, I'd like to turn -- so I'd like to just have -- say thank you to the Board and encourage you to allow the train to continue moving to its next step in 2030. (NRDC2_T19-4)

Agency Response: Staff appreciates the commenters' support for the agency's efforts to complete the rulemaking this year to implement these changes. Staff

also appreciates the specific recommendations associated with these comments, which are responded to elsewhere.

In response to comment NEXTGEN1_124-3, staff agrees with the commenter that transportation represents the largest source of emissions in California and that the LCFS should play a larger role in meeting the state's greenhouse gas reduction goals. This was acknowledged in CARB's 2017 Scoping Plan as well as in staff's Initial Statement of Reasons as a primary objective of the rulemaking. It is further recognized as the LCFS amendments call for a 20 percent CI reduction by 2030 and the 2017 Scoping Plan called for at least an 18 percent CI reduction by 2030.

C. Definitions

C-1. *Definition of Fuels*

C-1.1. Multiple Comments: *Definition of "Biomass-Based Diesel"*

Comment: According to the regulation, co-processed renewable diesel is defined as "biomass-based diesel when it is greater than 5% of the total diesel volume."[10] It is our strong preference that co-processed renewable diesel simply be termed "co-processed renewable diesel." Neither the Internal Revenue Service nor the U.S. Environmental Protection Agency—for Renewable Fuel Standard or associated programmatic purposes—considers co-processed renewable diesel to be "biomass-based diesel." We continue to recommend that CARB utilize existing federal government and fuel industry definitions to avoid unnecessary confusion, especially considering the inherently complex nature of these intersecting state and federal policies.

[10] Appendix A, page 7.

In addition, the Congress has specifically denoted that co-processed renewable diesel cannot be considered biomass-based diesel. 42 U.S.C. § 7545(o)(1)(D) states in relevant part that "Renewable fuel derived from co-processing biomass with a petroleum feedstock shall be advanced biofuel if it meets the requirements of subparagraph (B), but is not biomass-based diesel." Therefore, a state agency defining co-processed renewable diesel in the way CARB suggests would seem to conflict with federal law. (NBBCABA1_29-12)

Comment: We do not agree with the proposed definition change for biomass-based diesel and believe there could be unintended consequences. The proposed definition is as follows:

> "Biomass-based Diesel" means a biodiesel (mono-alkyl ester) or a renewable diesel that complies with ASTM D975-14a, (2014), *Specification for Diesel Fuel Oils*, which is incorporated herein by reference. This includes a renewable fuel derived from co-processing biomass with a petroleum feedstock. <u>However, biomass-based diesel should only include co-processed fuel to the extent that the co-processed renewable diesel is greater than 5 percent of the total diesel volume.</u>

One minor suggestion to improve clarity is to reverse the wording in the first sentence. As currently worded, it can be read to say that both biodiesel and renewable diesel must comply with ASTM D-975. However, B100 must meet D-6751, per the biodiesel definition, and likely would not meet D-975. If it was worded "Biomass-based Diesel" means a renewable diesel that complies with ASTM D975-14a (2014) or biodiesel (mono-alkyl ester), it would solve the problem.

The primary issue with the definition is the addition of the last sentence, which would mean that co-processed renewable diesel would only meet the definition of biomass-based diesel if the renewable portion was greater than 5% volume. The proposed addition creates numerous questions and creates potential problems.

- If a producer were to co-process less than 5%, how would the resulting product be defined or classified? Would it be considered diesel fuel or perhaps a diesel fuel blend? If it was classified as diesel, there would be no way to generate credits for the renewable portion of the product until the producer secured a provisional pathway (requires a minimum of 3 months operating data).
- If it is not biomass-based diesel, apparently the producer would not qualify for the temporary pathway in Table 8 for Biomass based Diesel (65 CI for plant oil feedstocks). Would the only temporary pathway it would qualify for be the one described as "Any diesel substitute feedstock-fuel combination not identified above", which would be at the proposed modified 2010 ULSD baseline CI of 100.95? This is a HUGE difference (100.95 vs. 65) and would result in deficit generation for co-processed renewable diesel less than 5%.
- Some pipelines will not allow shipment of diesel containing greater than 5% renewable diesel. Also, FTC rules require separate labeling of diesel containing greater than 5% renewable diesel. There two factors might lead a producer to choose to limit the co-processed renewable diesel to 5% or less.

We ask that ARB remove the proposed sentence addition to the Biomass-based Diesel definition. It appears the current proposed language would not allow credit generation for the renewable portion until a provisional pathway was approved and appears to generate deficits for this renewable volume. This seems punitive to entities who are working and investing to produce a renewable fuel that reduces the CI – the overall goal of the program. We would support either complete removal of the last sentence of the definition or language that clarifies that only the renewable portion of the resulting co-processed product would be classified as Biomass-based diesel (language proposed in the WSPA comments). (P661_55-3)

Comment: In § 96481(a)(18), the proposed change to the definition for "Biomass-based Diesel" does not address the problem indicated in the ISOR. The concern is that an entire volume of co-processed fuel might be considered Biomass-based Diesel under the current definition. However, simply adding that the renewable content must be more than 5% of the total diesel volume does not correct this. In the context that the term "Biomass-based Diesel" is used in the regulation, it would be better to amend the definition as follows:

> "Biomass-based Diesel" means a biodiesel (mono-alkyl ester) or a renewable diesel that complies with ASTM-D975-14a (2014), *Specification for Diesel Fuel Oils*, which is incorporated herein by reference. This includes <u>the renewable portion of</u> a renewable fuel derived from co-processing biomass with a petroleum feedstock.

Further, WSPA requests that, in the definition of bio-mass-based diesel, new language be removed from the definition, removal of this new language would allow co-processors with 5% or less renewable diesel use of a temporary pathway code with a CI of 65 gCO2e/MJ for feedstock derived from plant oils, excluding palm oil and a CI of 45 gCO2e/MJ for Fats/Oils/Grease Residues as specified in Table 8. (WSPA2_61-3)

Comment: 3. Redefine "Biomass-based Diesel" as "Alternative Diesel"

The "biomass-based diesel" definition is overly prescriptive in its specification only of biodiesel and renewable diesel. Other technologies, such as ethanol based Alcohol-to-Jet, are able to produce Synthetic Paraffinic Diesel (SPD) meeting ASTM D975 (http://www.astm.org/Standards/D975.htm) from ethanol feedstocks. To maximize the pool of low carbon diesel for the California road market, we recommend one of two options:

Option1: Rename "Biomass-based diesel" as "Alternative diesel" with the following definition:

"Alternative diesel fuel" means a biodiesel (mono-alkyl ester), a renewable diesel, or any other non-petroleum diesel that complies with ASTM D975, Specification for Diesel Fuel Oils, which is incorporated herein by reference."

This option would be consistent with the proposed definition and use of Alternative Jet Fuel throughout the regulation

Option 2: Add a separate definition for "Alternative diesel fuel":

"Alternative diesel fuel" means any non-petroleum-based diesel other than biodiesel or renewable diesel that complies with ASTM D975, Specification for Diesel Fuel Oils, which is incorporated herein by reference."

This option will require that all references to "Biomass-based diesel" be updated to read "Biomass-based diesel or Alternative Diesel Fuel".

Please see Attachment B for a list of references to "Biomass-based Diesel" within the regulation. (LANZATECH1_77-5)

> **Agency Response:** In response to this comment staff modified the regulation language to change the description of the "co-processed renewable diesel" included in the definition of "Biomass-based Diesel." "Biomass-based Diesel" now means *a biodiesel or a renewable diesel*.

C-1.2. *Definition of "Renewable Propane"*

Comment: REG opposes the current definition of renewable propane because it would exclude REG and other renewable diesel producers' renewable LPG from the program. Our butane content tends to be higher typically ranging from 4% to 7.5% though it is well under the 30% allowed in Europe. At this time, we are not aware of any attempts at selling renewable LPG as a neat fuel to end transportation users in the United States so it is much more likely to be used as a blendstock at inclusion rates of less than 50%. The final fuel product would still meet the spec used in 13 CCR § 2292.6[2]. Therefore, REG proposes that the definition for renewable LPG/propane be equivalent to the

Liquefied petroleum gas (LPG or propane) definition which references a definition in the Vehicle Code to avoid two sets of rules. A few others options included the following:[2]

[2] https://govt.westlaw.com/calregs/Document/I5A54795D3A244A0CBE38F008C8D4CB72?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default)

- "Renewable Liquefied petroleum gas (LPG or propane)" means a renewable fuel that has the same meaning as defined in Vehicle Code section 380.
    - As an alternative to the REG proposal above, CARB could add language requiring the final on-road propane fuel (renewable and/or fossil blend) must meet 13 CCR § 2292.6. This allows components like renewable LPG into the program while still ensuring the spec enforced by the California Department of Food and Agriculture is met.
    - Delete the renewable propane definition altogether and include it under the Liquefied petroleum gas (LPG or propane) definition.
    - Use the Vehicle Code section 380 definition until an ASTM spec for renewable LPG is developed. (REG1_88-4)

Agency Response: Staff acknowledges the commenter's support for changing the definition of "Renewable Propane." The definition of "Renewable Propane" has been modified and it now means *liquefied petroleum gas (LPG or propane) that is produced from non-petroleum renewable resources*.

C-1.3. *Definition of "Biogas"*

Comment: In § 95481(a)(13), WSPA recommends that, in the definition of biogas, the additional language "includes but not limited to" be added when describing potential sources from which biogas may be derived. (WSPA2_61-2)

Agency Response: In response to this comment, staff modified the Regulation language to make it explicit that biogas is "…derived from sources, including but not limited to, anaerobic decomposition of organic matter in a landfill, lagoon, or constructed reactor (digester)."

C-1.4. *Definition of "Biomethane"*

C-1.4a. Multiple Comments: *Support for the Modification to the Definition of "Biomethane"*

Comment: 1. Definition of "Biomethane" – We applaud ARB's proposal to include within the definition of "biomethane" innovative processes such as the gasification of biomass to produce syngas and subsequent methylation to obtain methane of biological origin. (CRF1_45-2)

Comment: Page III-4: The current LCFS regulation omits biomethane from non-biogas sources, such as gasification of biomass to produce syngas. The Staff Report proposes to expand the definition of "biomethane" to include synthetic natural gas derived from

renewable resources and changes the description of the fuel to simply one that "meets pipeline quality natural gas standards." In addition, the Staff Report proposes that the modifier "biogas-derived" is removed from the definition of fuels made from biomethane. The Task Force strongly supports the Staff Report's recommendation to no longer limit the production of biomethane to biogas derived from AD and to expand it to include non-combustion thermal CTs. (TASKFORCE1_89-4a)

Comment: a. BAC agrees that the definition of biomethane should be expanded to include methane derived from gasification of organic material.

BAC supports expanding the definition of biomethane to include methane that is derived from gasification of organic material. The draft points out correctly that a number of pilot projects are converting biogas from gasification of organic waste to methane, which can be used as a vehicle fuel. Including biomethane derived from gasification of organic material would help the state to reduce black carbon from wildfires and controlled burns of forest and agricultural waste, and would help the state to meet the landfill diversion requirements of SB 1383 since a large part of organic landfill waste (wood and construction debris) is not suitable for anaerobic digestion. (BAC1_99-4a)

Comment: We support staff's recommendation to redefine RNG to put it in an engine and not the pipeline. After all, the engines use RNG and not the pipeline. So we support staff's good work on making sure that the manufacture's spec for the engine defines RNG. (CCC1_T52-2)

> **Agency Response:** Staff appreciates the commenters' support for the amendment to the definition of biomethane.

C-1.4b. Multiple Comments: ***Definition of "Biomethane" is too Limited***

Comment: 1. Section 95481(19) – Biomethane definition - The definition requires that biomethane meet pipeline quality natural gas standards. This is far too stringent and contrary to actual practice. Pipeline quality requirements, which are currently being re-evaluated, have been the focus of objection from the biomethane community and have thwarted the intent of AB 1900. Wastewater treatment plants currently use biomethane to produce electricity, heat, and other energy on-site to offset importation of energy from the grid, which does not qualify under this definition. In some cases, the excess electricity is exported to the grid. Similarly, biomethane is being produced and used as a transportation fuel, which does not meet today's pipeline injection standards. These alternative uses should not be precluded. This definition should be modified to read:

"Biomethane" is ~~primarily~~ means methane derived from biogas, or synthetic natural gas derived from renewable resources, after carbon dioxide and other impurities present in the biogas are chemically or physically separated from the gaseous mixture. Biomethane has equivalent chemical, physical, and performance characteristics as methane gas. ~~which has been upgraded to meet pipeline quality natural gas standards~~.

~~Biomethane contains all of the environmental attributes associated with biogas and can also be referred to as renewable natural gas.~~ (CASA1_94-3)

Comment: Clean Energy agrees with Staff's intent to expand the definition of biomethane to include methane that is derived from gasification of organic material. However, we disagree with the recommendation in the definition that requires biomethane to meet utility pipeline standards. There are at least three registered biomethane projects in California that currently facilitate onsite vehicle fueling. Two of these projects (Clean Energy partners) use biomethane produced from diverted organic waste digesters to fuel their company-owned refuse fleets. Since the biomethane is delivered directly into the vehicle, it should not be held to the established California pipeline injection standards. Furthermore, the California Public Utilities Commission (CPUC) has adopted the most stringent gas quality standards in the country which do not align with current engine specifications which is why the State enacted SB 840 requiring the CPUC to review and possibly amend the California pipeline injection standards. Requiring all biomethane to meet California pipeline injection standards even if not injected into a pipeline is overly restrictive and will slow development of in-state sources of RNG. Clean Energy recommends that Staff remove this provision requiring biomethane to meet pipeline injection specifications. (CE1_92-14)

Comment: However we caution against the proposed use of pipeline standards as a shortcut to defining biomethane. California's current standards for injecting biomethane into common carrier gas pipelines are unnecessarily restrictive. In particular, the requirement that biomethane have an energy density of 990 Btu per standard cubic foot exceeds the requirement in almost every other state. More importantly, it exceeds the energy density required by natural gas vehicle engines and combustion turbines. To achieve this unnecessary standard, cleanup equipment must be oversized to allow for greater recycle rates. More recycle means more energy consumption, which is wasteful. ARB could do far better than adopt a biomethane definition that has an unnecessarily high carbon footprint. To the extent that ARB feels the need to refer to "biomethane" as meeting pipeline standards, it should retain a more pragmatic definition for "renewable natural gas." (CRF1_45-3)

Comment: 2. The definition of biomethane is not accurate, would significantly increase the cost of many biomethane projects, and would disadvantage instate biomethane producers.

…

2. The definition of biomethane is not accurate, would increase the cost of instate projects, and would put instate projects at disadvantage.

The proposed amendments would revise the definition of biomethane in both helpful and harmful ways, including two proposed changes that are not accurate.

…

b. Biomethane should NOT be required to meet pipeline standards unless it will be injected into a utility pipeline.

BAC strongly objects to two other changes to the definition of "biomethane." Most importantly, biomethane under the LCFS should not be required to meet utility pipeline standards. At least two biomethane producers that participate in the LCFS program are using the biomethane to fuel vehicles onsite: the CR&R project in Riverside County and the South San Francisco Scavenger project, which are using biomethane from diverted organic waste to fuel garbage trucks and other vehicles onsite. Why should those biomethane producers be required to meet pipeline standards to be eligible for the LCFS, when the biomethane doesn't have to go in the pipeline? The LCFS is a vehicle fuel program, not a pipeline injection program.

Requiring biomethane to meet pipeline standards would also put instate biomethane producers at even greater disadvantage compared to out of state biomethane producers. The California Public Utilities Commission adopted the most stringent standards in the country pursuant to AB 1900 (Gatto, 2012). Those standards have put California biomethane producers at a severe disadvantage compared to biomethane producers that can inject into pipelines in other states, which is why the state enacted SB 840 in 2016 to require the CPUC to revisit some of the pipeline biogas standards.[4] Requiring biomethane under the LCFS to meet pipeline standards – whether or not the biomethane needs to be injected into a utility pipeline - is overly restrictive and will hurt the instate producers who are needed to meet the requirements of SB 1383.

[4] SB 840, section 11, adding Public Utilities Code section 784.1.

(BAC1_99-4)

> **Agency Response:** Staff agrees that the proposed definition was too limited and modified the definition of biomethane in response to these comments. The modified definition encompasses all uses of biomethane that are recognized under the LCFS.

C-1.4c. *Include Municipal Solid Waste in Definition of "Biomethane"*

Comment: The definition of "renewable natural gas" is used interchangeably with "biomethane" in Section 95481(a) of the proposed regulations. The Task Force requests that CARB clarify whether definition of "biomethane" and "renewable natural gas" will include gas produced from feedstocks such as municipal solid waste. (TASKFORCE1_89-4b)

> **Agency Response:** Staff modified the definition in response to this comment to specifically include methane derived from the organic portion of municipal solid waste.

C-1.4d. *"Renewable Natural Gas" is not interchangeable with "Biomethane"*

Comment: c. The proposed definition of biomethane is wrong to equate biomethane and RNG, which overlap but are not always the same.

The proposed definition is also incorrect to equate biomethane with Renewable Natural Gas. RNG is a broader term that can include Power to Gas and other forms of renewable natural gas substitutes that are not derived from biological sources. It makes no sense to call Power to Gas made from renewable power and water "biomethane" when it does not come from organic material.

BAC recommends, therefore, that the definition of biomethane include the methane derived from biological (organic) material, regardless of conversion method, and that it be required to meet vehicle engine standards, not utility pipeline standards. BAC also recommends removing the statements that "biomethane" and RNG are interchangeable, which they are not. (BAC1_99-4b)

> **Agency Response:** Staff recognizes that there are contexts in which it may be necessary to distinguish "renewable natural gas" and "biomethane." However, for the purpose of the LCFS regulation definition, staff seeks only to provide sufficient information to clarify how a fuel pathway can be certified and reported to the LCFS. As stated in the ISOR: "The term biomethane is interchangeable with renewable natural gas for the purposes of this subarticle, as staff is not aware of any need to distinguish them." Any renewable natural gas substitute, such as fuel produced by Power to Gas, would be subject to the same requirements for CI application and reporting as a biomethane fuel.

C-2. ***Referring to ASTM Standards and Methods***

Comment: 1. Refer to ASTM Standards and Methods without specifying the year of publication

When referencing an ASTM Standard only the standard # should be given not the year it was issued. ASTM standards are updated frequently to represent available equipment, latest methodologies etc. Referencing outdated standards and methods makes it difficult to comply with the regulation as written and creates the potential for confusion.

For referencing ASTM standards, provide the link to the ASTM website, www.astm.org.

Please see Attachment A for a list of references to ASTM Standards and Methods within the regulation with a recommendation for how to modify them. (LANZATECH1_77-3)

> **Agency Response:** In response to this comment, staff modified the proposed regulation amendment language to remove references to the ASTM specifications from the definitions. For ASTM specifications referenced for tests required by the ADF regulation, it is necessary to specify the year of publication. ASTM standard documents state that, "all ASTM standards are subject to revision at any time by the responsible technical committee and must be reviewed every five years, if not revised, reapproved or withdrawn." As commented by LANZATECH, ASTM standards are updated frequently to represent available equipment, latest methodologies, etc. Therefore, it is

necessary to specify the ASTM test method with the year referenced for consistency and test reproducibility when ASTM test methods are referenced.

C-3. *Definition of Feedstocks*

C-3.1. Multiple Comments: *Definitions of "Animal Fat" and "Yellow Grease"*

Comment: In § 95481(a)(7), the draft regulation proposes in the definition for animal fat that "Yellow grease" must be reported under an applicable animal fat pathway if evidence is not provided to the verifier or CARB to confirm that it is solely used cooking oil. WSPA recommends that CARB consider the inclusion of pro-rating animal fat and used cooking oil as an option. By replacing "…that it is solely used cooking oil." with "…the ratio of animal fat to used cooking oil within the yellow grease in order to pro-rate the carbon intensity." (WSPA2_61-1)

Comment: REG appreciates the effort CARB staff made to simplify the animal fat definition. However, we believe it may be more confusing under the proposed changes. Confirming that yellow grease is solely used cooking oil seems contradictory. Does the proposal mean we have to prove that 100% of the yellow grease is used cooking oil for classification as used cooking oil? Or does it mean that there is a way to determine that 50% of the yellow grease is used cooking oil and classify it as such? We have provided suggested edits based on our assumption that the meaning is the latter.

- "Animal Fat" means the inedible fat that originates from a rendering facility as a product of rendering the by-products from meat processing facilities including animal parts, fat and bone. "Yellow grease" must be reported under an applicable animal fat pathway if evidence is not provided to the verifier or CARB to confirm the amount of UCO present.
- "Yellow Grease" means a commodity produced from a mixture of: (A) used cooking oil, and (B) rendered animal fats that were not used for cooking. This mixture often is combined from multiple points of origin. Yellow grease must be characterized as "animal fat" if evidence is not provided to the verifier or CARB to confirm the amount of UCO present. (REG1_88-3a)

Agency Response: In response to this comment, staff modified the Regulation definitions of animal fat and yellow grease to clarify that a portion of yellow grease may be characterized as used cooking oil, if evidence is provided to confirm the quantity that is used cooking oil. If no evidence is provided to confirm the quantity of yellow grease that is used cooking oil, staff would make the conservative assumption that yellow grease is comprised solely of animal fat. Staff appreciates the commenters' suggestions as they align with the intention to demonstrate accurate characterization of specified source feedstocks.

In response to WSPA2_61-1, staff would like to clarify that separate CI values are certified for the two pathways; rather than "pro-rate the carbon intensity," a fuel reporting entity would report the quantity of fuel that was derived from each feedstock under its respective pathway.

C-3.2. *Definition of Waste Oils*

C-3.2a. Comment: Neste supports ARB's efforts to attempt to distinguish between different grades of waste oils. However, the terms "Brown Grease", "Used Cooking Oil", and "Yellow Grease" do not align with normal and industry-standard nomenclature and have the strong potential to create confusion and increase misidentification between commercial parties and the regulatory expected documentation. Neste instead proposes that the terms be used interchangeably (as the are used commercially) and that the processing and mixing differences in the supply chain that the proposed definitions appear to be contemplating instead be documented via the verification efforts. (NESTE1_76-12)

> **Agency Response:** Staff recognizes that the industry's needs to differentiate among grades of oils (for example, on the basis of free fatty acid content) differ from the needs of the LCFS program to differentiate based on the upstream emissions associated with a given feedstock. Staff has worked with industry stakeholders to develop these regulatory definitions, and seeks only to provide sufficient information to clarify how each material can be reported to the LCFS. The proposed distinctions are necessary to allow fuel producers who specifically track their feedstock's points-of-origin, or those who use feedstock from a single source, to accurately quantify their CI. However, the definitions also allow a producer who uses the terms interchangeably (for example, purchases yellow grease as a commodity and has no information to further distinguish the sources) the option to simply report their feedstock under an applicable animal fat pathway.

C-3.2b. Comment: Table 8, Temporary Pathways for Fuels with Indeterminate CIs, identifies "Fats/Oils/Grease Residues" but fails to define the term. Neste proposes that the definition should be added as follows: "Fats/Oils/Grease Residues include, but are not limited to, processing residues that are not the main product of the production process, neither from a technical nor an economical perspective to the total production process." (NESTE1_76-13)

> **Agency Response:** Staff generally agrees with the commenter's characterization of the temporary pathway, but does not believe a definition is required because it is generally understood.

C-4. *Definition of "Biomass"*

Comment: 2. Modify the definition of "Biomass"

The definition of "Biomass" excludes the use of algae, cyanobacteria and other microbes, as well as other types of biological organisms that can be used as biocatalysts, fuel sources, or feedstocks for the production of fuels. It is also unnecessarily limited in its references to wastes, which are a high priority source of feedstock for low carbon fuels. We recommend the following more technology-neutral

definition in order to ensure that the LCFS remains a robust regulation as new technologies come online:

"Biomass" means biogenic ~~plant and animal~~ material from plants, animals, and other organisms, especially agricultural ~~or~~, forest, or other waste products, which can be used as a biocatalyst, a source of fuel, or a feedstock for the production of fuel, soil amendment, or fertilizer. (LANZATECH1_77-4)

> **Agency Response:** In response to this comment, staff modified the definition of biomass to align with the U.S. EPA's definition. Staff believes this change fully encompasses the recommendations made by the commenter by explicitly including microorganisms and wastes as sources of biomass. In addition, staff note that although "biocatalyst" is not explicitly listed as a use for biomass, the modified proposed definition eliminates the list of uses, which did not serve a purpose in the Regulation.

C-5. *Definition of "Rack"*

Comment: In particular, we wish to comment on the following: (1) the potential ambiguity associated with the proposed definition of "rack,"[1] and encourage CARB to use a different definition to allow the transfer of the compliance obligation through to the point in the distribution chain that is traditionally considered the rack;

[1] Section 95481(108) of the Proposed Regulation Order amending the LCFS regulation includes language defining "Rack" as, "a mechanism for delivering motor vehicle fuel or diesel from a refinery or terminal into a truck, trailer, railroad car, or other means of non-bulk transfer". See CARB, Appendix A: Proposed Regulation Order, Low Carbon Fuel Standard (Mar. 6, 2018), https://www.arb.ca.gov/regact/2018/lcfs18/appa.pdf ("**Proposed Amendments**").

…

1. Definition of Rack

As written, the proposed amendments would prohibit transfers of credit and deficit generator status to an entity acquiring title to fuel below the rack. The proposed amendments then define the rack as a "mechanism for delivering motor vehicle fuel or diesel from a refinery or terminal into a truck, trailer, railroad car, or other means of non-bulk transfer." This proposed definition is sufficiently broad such that it could be interpreted to cover transfers of fuel that are typically thought of as being "above the rack." The rack is commercially understood by fuel producers, refiners and retailers to be facilities used to transfer gasoline, diesel and other products for delivery to retail fuel dispensers like gasoline stations, convenience stores and truck stops.[2] In most instances, the rack is located at a terminal where ethanol is added to gasoline and where the final diesel blend is sold to "jobbers" who then truck the gasoline and diesel to retail locations.

[2] See Fuels Institute, *Assessment of the U.S. Fuel Distribution Network.*

The proposed definition, however, is broader than the industry concept of the rack such that it could capture terminals that are actually in the middle of the distribution chain. For instance, rail has become a common way to ship refined product from refineries and

import locations to terminals where it is stored for significant periods before being blended with ethanol and shipped to retail fuel dispensers or instead being transshipped, unblended, to another terminal by pipe or rail. Under CARB's proposed definition of the rack, there could be confusion that parties are prohibited from transferring the compliance obligation beyond the initial point where it is added to the railroad car. Similarly, the proposed definition could be construed so as to include any point where unblended denatured ethanol (*i.e.,* e98) is transferred from a terminal to a truck for shipment to an actual blending terminal. Therefore, under the proposed definition of "rack," distributors and marketers may believe they are unnecessarily constrained from contracting with counterparties who are better suited to retain the LCFS compliance obligation.[3]

[3] See Proposed Amendments at EX-2, I-3, III-33-35, IV-2, V-10.

Given the potential for the proposed definition of "rack" to preclude wholesale fuel distributors from transferring their credit or deficit generator status downstream, we propose CARB consider and adopt a definition of "rack" that better aligns with the expectations and custom of commercial market participants. For LCFS purposes, CARB's definition of "rack" should comport with the common understanding of that term among companies engaged in the fuel distribution business [4] and be consistent with the economics and structure of the market.[5] In our view, such a definition would focus on the identity of an intended recipient of a transfer of fuel. Accordingly, we recommend that CARB adopt a definition of "rack" that is a variation of "*the last point of sale before retail distribution.*"

[4] "Rack Sales" are commonly understood to be wholesale truckload sales or smaller sales of gasoline where title transfers at a terminal. See EIA, Definitions, Sources and Explanatory Notes, https://www.eia.gov/dnav/pet/TblDefs/pet_cons_refmg_tbldef2.asp.

[5] Market prices for refiner gasoline is segmented by EIA in terms of wholesale markets (*i.e.*, sales for resale) and retail markets (*i.e.*, sales to end users). See EIA, Refiner Gasoline Prices by Grade and Sales Type (Mar. 1, 2018), https://www.eia.gov/dnav/pet/pet_pri_refmg_dcu_nus_m.htm.

(ES1_97-1)

Agency Response: The definition of "rack" proposed by staff is consistent with the definition provided in the in the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (MRR) and the Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms (Cap-and-Trade). Staff believes the proposed definition of "rack" is well-understood and accepted in the industry as numerous stakeholders and fuel providers are already successfully complying with the MRR and Cap-and-Trade regulations. Further, staff proposed to classify different scenarios with reference to the rack, which would establish clear responsibility for reporting fuel export in the LRT-CBTS in different scenarios.

C-6. Multiple Comments: *Definition of "Green Tariff"*

C-6.1. Comment: In § 95481(a)(61), WSPA requests that ARB verify the year referenced for Senate Bill 43, as SB 43 of 2016 relates to health care coverage. (WSPA2_61-4)

Agency Response: In response to this comment, staff modified the Regulation language to correct the inaccuracy. The Green Tariff Shared Renewables program was established pursuant to California Senate Bill 43 in 2013, not 2016.

C-6.2. Comment: The definition of "green tariff" has been provided, and further clarified that the Green Tariff Shared Renewable (GTSR) program is only one form such a program can take as the GTSR program only applies to California's three largest electric utilities (PG&E, Edison, and SDG&E).

…

(61) "Green Tariff" means a program where a retail seller of electric energy offers its customers an opportunity to purchase a portfolio of energy sourced solely from renewable or low carbon intensity energy resources such as the Green Tariff Shared Renewables" program established pursuant to California Senate Bill 43 (2016) and defined under the California Public Utilities Code sections 2831-2833.. (CCSF2_90-2b)

Agency Response: In response to this comment, staff modified the Regulation definition from the specific "Green Tariff Shared Renewables" program in the original proposal, to the more general "Green Tariff" as suggested. The revised definition more clearly reflects the relevant provision in 95488.8(i)(1)(B), which states: "Low-CI electricity can be indirectly supplied through a green tariff program (including the Green Tariff Shared Renewables program)…."

C-7. *Definition of "Load-Serving Entity"*

Comment: The definition of "Load Serving Entity" should be expanded beyond the definition of "company" to include government entities (such as POUs and CCAs),

…

(79) "Load-Serving Entity" means any company, government agency, or entity that (A) sells or provides electricity to end users located in California, or (B) generates electricity at one site and consumes electricity at another site that is in California and that is owned or controlled by the company. A load-serving entity does not include the owner or operator of a co-generator. (CCSF2_90-3)

Agency Response: Staff appreciates commenter's recommendation to update the definition of Load-Serving Entity. As part of the 15-day changes, staff updated the definition and replaced "company" with "entity" to make it comprehensive for LCFS purposes.

D. Fuels Subject to the Regulation

D-1. *Alternative Jet Fuel*

D-1.1. Multiple Comments: *Support for the Proposed Alternative Jet Fuel Provisions*

Comment: WSPA supports the inclusion of Alternative Jet Fuel (AJF) under the opt-in provision, while retaining the exemption status for conventional jet fuel. (WSPA2_61-5)

Comment: REG strongly supports the addition of alternative jet fuel … as opt-in fuels… (REG1_88-5a)

Comment: REG supports the drafted rules for alternative jet fuel... In addition, we agree that CARB should not require entities buying below the rack to report to LRT-CBTS unless they export the fuel. (REG1_88-8b)

Comment: And also, we're very excited about the opportunity moving forward to get into both renewable propane and the jet fuel market. So obviously you can tell that we're supportive of the provisions on renewable jet fuel. (REG2_T16-1)

Comment: We believe that the addition of alternative jet fuel to the scope of the LCFS is appropriate and will help stimulate the production and use of alternative jet fuel in California.

… We support…the addition of alternative jet fuel to the scope of the LCFS… (ENERKEM1_135-5)

Comment: We support the inclusion of alternative jet fuels in the LCFS as a way to address this significant and growing source of GHG emissions. Reducing emissions from aviation has been difficult, and inclusion in the LCFS would help to shift jet fuels toward more sustainable alternatives to petroleum. (CCA1_52-3)

Comment: While efforts to reduce carbon fuel emissions have focused on ground sources, it's time LCFS looks skyward for greater reductions. CCA supports the inclusion of alternative jet fuels in LCFS to assist the aviation industry in shifting toward more sustainable alternatives to petroleum. (CCA2_T12-3)

Comment: We also support the alternative jet fuel option. (HMO2_T15-7)

Comment: As detailed below, A4A and its member airlines strongly support the inclusion of alternative jet fuel (AJF) as an eligible credit-generating fuel on an opt-in basis. Such an approach would provide needed regulatory incentives for AJF, support the developing California advanced biofuels industry, lower the cost of compliance for obligated parties, and advance the State's environmental goals. Accordingly, while we propose a few changes to the carbon intensity provisions that would apply to AJF, we support CARB's proposal to add AJF as an LCFS credit-generating fuel and appreciate the extensive work CARB staff members have done on this proposal.

I. A4A, AJF and Significant Emissions Benefits from AJF as an Eligible Credit-Generating Fuel under the California LCFS

By way of background, A4A and its members are part of a global aviation coalition that has committed to a 1.5% annual average fuel efficiency improvement through 2020 and carbon neutral growth from 2020, subject to critical aviation infrastructure and technology advances achieved by government and industry. The initiatives our airlines are undertaking to further address greenhouse gas (GHG) emissions are designed to responsibly and effectively limit their fuel consumption, GHG contribution, and potential climate change impacts, while allowing commercial aviation to continue to serve as a key contributor to the U.S. and local economies. At the same time, we continue to build upon our strong record of reducing conventional air pollutant emissions.

The availability of sustainable AJF in significant quantities is a key pillar to the achievement of the industry's goals, and A4A and its members are working hard to lay the groundwork for the establishment of a sustainable AJF industry. AJF is particularly critical to the aviation industry's decarbonization strategy as aviation, unlike ground transportation, cannot electrify in the near-term and is therefore reliant upon liquid fuels.

There is particularly great interest among biofuel producers and A4A members in producing and utilizing sustainable AJF in the California market. United Airlines began using commercial quantities of AJF at Los Angeles International Airport in 2016 pursuant to an off-take agreement with AltAir Fuels to purchase of up to 15 million gallons of AJF over 3 years. United has also made a $30 million equity investment in Fulcrum BioEnergy that includes provisions to co-develop up to five facilities and purchase at least 90 million gallons of AJF per year over ten years. FedEx and Southwest Airlines have similarly committed to each purchase 3 million gallons per year from Red Rock Biofuels for expected use in Northern California, and JetBlue has signed a 10-year off-take agreement with SG Preston for up to 10 million gallons of AJF per year. As the AJF industry continues to mature, these and other member airlines are actively exploring additional agreements, and the prospect of an LCFS credit for AJF is an important economic factor in these agreements. (A4A1_57-1)

Comment: We offer our strong support of ARB's proposal to include alternative jet fuel, referred to as AJF, as an eligible credit-generating fuel under the LCFS, though we do request two technical changes to the proposal.

We take our role in controlling greenhouse gas emissions very seriously. U.S. airlines have improved their fuel efficiency by 120 percent since 1978, saving over 4 billion metric tons of CO2 emissions.

Our global aviation coalition has adopted aggressive greenhouse gas emission reduction goals for which a key strategy is the use of AJF.

In 2016 United Airlines began using AJF at LAX under an agreement with AltAir Fuels to purchase up to 15 million gallons of their fuel over three years. United and other A4A members are pursuing additional AJF deployment opportunities in California.

Unfortunately, the production of AJF is disincentivized in significant part because it's been ineligible for LCFS credits, making the production of renewable diesel much more economical than AJF.

Alternative fuel facilities produce both renewable diesel and AJF; and allowing LCFS credits for AJF would significantly improve the economics of new and existing facilities, allowing them to generate credits from all alternative transportation fuels produced.

A National Renewable Energy Laboratory analysis demonstrates that allowing AJF to be an eligible credit-generating fuel would stimulate additional production of other renewable transport fuels, including renewable diesel. For these reasons, United and A4A strongly support ARB's overall proposal for AJF. (UAA4A1_T36-1)

Comment: Neste as a producer of low-carbon, renewable jet fuel strongly supports the inclusion of alternative jet fuel in the LCFS program as an opt-in credit generating fuel. Emissions from air travel still remain a significant source of greenhouse gases. Additional strong incentives in the LCFS are necessary to continue to support the efforts of airline, airports, and international organizations to build an advanced biofuels industry, lower the cost of compliance for obligated parties, and to advance California's carbon reduction goals. (NESTE1_76-3)

Comment: I also want to echo some of Graham's comments earlier. While we very much applaud and appreciate the effort to put alternative jet fuel into the program as an opt-in credit generator, Neste as a developer of that fuel is looking forward to participate in this program. (NESTE2_T11-4)

Comment: We would like to firstly express our strong support for the inclusion of Alternative Jet Fuel (AJF) in the LCFS, and to acknowledge the exemplary work of ARB staff and management in positioning California as the global leader in supporting low carbon fuels.

…

Including AJF in the LCFS makes California an even more attractive location to build a commercial scale ATJ facility. (LANZATECH1_77-1)

Comment: The primary purpose of this letter is to express our strong support for the inclusion of AJF in the LCFS, and to acknowledge the exemplary work of ARB staff and management in working with the AJF Producers, A4A, and the aviation industry. We literally have been working with the ARB for two years in the development of this rule. Throughout this time, we have communicated steadily through numerous public workshops, meetings, informal written comments, phone calls, and emails. ARB has been actively engaged throughout this process and has thoroughly considered and integrated our input into the proposed rule. (AJFP1_102-1)

Comment: Chevron is very supportive of staff's proposal to allow credits to be generated for alternative jet fuel supplied in the state of California. Establishing additional sources of credits that are based on sound science and encourage innovation

will benefit the program. We also concur with staff's conclusion that allowing credits for alternative jet fuel will encourage investment in renewable diesel production facilities. This will not only spur growth, but may have some positive effect on the overall cost of the LCFS to the California transportation market. (CHEVRON1_112-3)

Comment: Section 95482(b) – Support for Addition of Alternative Jet Fuel as an Opt-In Fuel

As a California-based company that produces Renewable Diesel, Kern understands the benefit for including AJF as part of the LCFS program and would like to show its support in favor of this proposed amendment. Kern agrees that incorporating AJF into the LCFS shows California's interest in addressing a significant source of GHG emissions and may promote increased investment in facilities that are currently producing Renewable Diesel. Kern is encouraged by ARB's inclusion of this opt-in fuel in such a way that the use of conventional jet fuel will not generate deficits, making this provision a keen demonstration of how the program should incent additional renewable fuel opportunities. (KERN1_115-8)

Comment: *NextGen Supports Proposed Alternative Jet Fuel Provisions*

At present, air travel accounts for approximately 10% of transportation-related GHG emissions in the U.S. Decarbonizing this sector presents a particular challenge for policymakers since many of the technologies which show promise towards reducing on-road emissions will struggle to meet the technical requirements for commercial air travel. Low-carbon analogues to petroleum-based jet fuel, such as biofuels, are widely regarded as an obligatory element of a sustainable transportation system. The LCFS is therefore an excellent framework from which to develop market-based incentives.

NextGen strongly supports the inclusion of low-carbon alternatives to conventional petroleum jet fuel under the LCFS. We agree with the basic principles outlined by Staff, but suggest on additional consideration:… (NEXTGEN1_124-44)

Comment: On behalf of United Airlines, this letter is to express our strong support for inclusion of alternative jet fuel (AJF) within the Low Carbon Fuel Standard (LCFS), as proposed in your draft "Low Carbon Fuel Standard and Alternative Diesel Fuels Regulation" released March 6, 2018. As you know, United strongly supports inclusion of AJF in the LCFS, and appreciates your work and the work of your staff on this issue.

Allow AJF to generate LCFS credits is intended to support further development of the California advanced renewable fuel industry, bring clean energy jobs to California, and create the greatest opportunities for airlines to support California's GHG emission reduction objectives. While there are steps we can take to reduce GHGs, such as electrification of ground service equipment, increasing the supply and use of AJF is by far the most effective tool airlines have to reduce our carbon footprint. (UNITED1_B12-1)

Comment: We applaud CARB's efforts to add this major fuel product to the Low Carbon Fuel Standard (LCFS) Program. Jet fuel is a substantial portion (approximately

20% – 5 billion gallons/year) or the petroleum-based fuel that is manufactured and distributed in CA. Combustion of jet fuel is a significant contributor in the production of greenhouse gases that is impacting world-wide climate change.

By adding jet fuel into the LCFS program as a voluntary component, California can enhance and encourage the development of low carbon alternative jet fuel, which is the fastest growing segment of petroleum fuel demand today. The U.S. Energy Information Administration (EIA) in their 2018 Energy Outlook estimates jet fuel demand will grow 67% from 2017 to 2050, more than any other transportation fuel. (ALTAIR1_B13-1)

Comment: San Francisco International Airport ("SFO") appreciates the opportunity to demonstrate support for the inclusion of alternative jet fuel ("AJF") on an opt-in basis through proposed amendments to the Low Carbon Fuel Standard ("LCFS") currently under consideration by the California Air Resources Board ("ARB").

SFO is actively exploring options for future delivery of AJF to meet the demand of our airline partners and achieve our five-year Strategic Plan goal of carbon neutrality by 2021.

The proposed expansion of the ARB's market-based credit program will help the commercial aviation sector access low-carbon fuels. SFO believes cost-competitive AJF provides a real opportunity to reduce carbon and other emissions, hedge against business risk from forecasted fuel supply scarcity, as well as provide a healthier local environment for our workforce. We also recognize how critical the LCFS is to draw AJF industries to California to enable airports to attain these benefits. AJF is currently produced in very limited supply and is utilized most effectively where it is cost competitive with conventional jet fuel.

…

SFO is also commissioning a feasibility study to explore AJF production, delivery, and storage pathways to enable fuel suppliers and buyers to accept AJF deliveries at our facilities. There is immense interest in AJF, and the proposed LCFS amendments would help surmount the high adoption hurdles. (SFO1_B18-1)

Comment: SFO supports the inclusion and applauds the consideration of alternative jet fuel on an optimum basis for the proposed amendments to the Low Carbon Fuel Standard. We are actively exploring the pathways for future delivery of AJF to meet the demand of our airline partners and achieve our five-year strategic plan goal of carbon neutrality by 2021.

Just this month we commissioned a study of alternative jet fuel supply and infrastructure needs for our airport, and we also regularly convene a working group of nearly 60 stakeholders - that includes our airline partners and fuel producers - to drive SFO's progress toward SFO -- or sorry -- towards alternative jet fuel adoption. (SFO2_T17-1)

Comment: The California Airports Council (CAC) appreciates the opportunity to provide our support for the inclusion of alternative jet fuel ("AJF") on an opt-in basis

through the proposed amendments to the Low Carbon Fuel Standard ("LCFS") regulations currently under consideration by the California Air Resources Board ("ARB"). This market-based incentive program being considered by the Board will further expand California's rich history in facilitating the production and use of low carbon fuels to a new sector that is well positioned and eager to lead: commercial aviation. Our Airports' recognize cost-competitive AJF as a high value opportunity that can help elevate our competitiveness in a global market, hedge against business risk from forecasted fuel supply scarcity, and also enable a healthier local environment for our workforce. We also recognize how critical the LCFS is to draw AJF to California to enable our Airports to attain these benefits, as AJF is currently produced in very limited supply and is only being purchased where it is cost-competitive with conventional jet fuel and due to sponsoring jurisdictions' regulatory incentive programs.

The CAC represents the 31 commercial service airports in the state, which provide services to over 200 million passengers annually, accounting for over 12% of all U.S. passenger enplanements. Eleven of California's commercial service airports ranked in the top 100 busiest airports in the nation in 2016, while serving as the nation's gateway to the Pacific Rim. The CAC is governed by Airport Directors and represents the views of California airports before federal, state and local government policymakers and regulators in matters of importance to airport operations, financing and security. We see ARB's proposed LCFS amendments, which include AJF, as related to all three.

AJF represents a way to mitigate a significant business risk for our industry, which anticipates immense market growth in the coming years, with no added growth of energy supply and no/limited pipeline access expansion forecasted. This security of a diversified, and cleaner, supply will not only mitigate these stated risks but allow for airport economic development and resultant social and environmental gains. However, current AJF supply is incredibly limited, with total global production less than 20 Million gallons/year. For reference, San Francisco International Airport alone consumes nearly 1 Billion gallons of jet fuel each year. Without an incentive for producers to supply the California market, competitor foreign destinations (*likely European Airports*) will attract all available AJF supply through airlines interested in accessing regulatory financial incentives and avoiding related environmental taxes and fees. The remedy is simple: ARB's inclusion of AJF in the LCFS will draw production to California, increasing supply and allowing this emergent, and environmentally beneficial, market to form here, supply to increase, and AJF fuel prices to decrease over time. (CAC1_49-1)

Comment: We come here to support the inclusion of an alternative jet fuel in the Low Carbon Fuel Standard program as it aligns with goals of airports for reducing greenhouse gas emissions and creating a healthier environment around local communities.

As mentioned earlier, alternative jet fuel production is limited in supply currently, with only five producers in the market. Also, globally, there's less than 20 million gallons of alternative jet fuel being produced.

Biofuel production is expensive, so producers are going into areas of the world where this can help reduce the burden. So with the ARB's inclusion of alternative jet fuel in the LCFS credit production, we'll ultimately be increasing supply and reducing cost, and this will be incredibly beneficial to California's environment. (CAC2_T21-2)

Comment: 5. We support allowing alternative jet fuel to opt-in to the program

We support CARB's proposal to allow alternative jet fuel (AJF) to generate LCFS credits as an opt-in fuel. We mirror stakeholder comments on this issue, namely:

"By including low carbon AJF in the program, CARB will stimulate the development of biofuels for a sector of transportation that may lack other effective options for decarbonization and help California attain its greenhouse gas reduction goals."

NRDC also notes that the inclusion of alternative jet fuel will also prevent the effects of encouraging a refinery to produce on-road renewable diesel in lieu of renewable-based jet fuel, allowing the refinery to optimize the production based on demand from fleets.

As a separate stakeholder comment letter notes, "By sending a clear and long-term market signal that AJF is eligible to generate LCFS credits in addition to Renewable Fuel Standard credits (known as RINs), CARB is facilitating investment and development in the de-carbonization of the aviation sector. This pioneering work by California is crucial given the anticipated growth of the aviation sector, the technical and energy intensive demands of this sector, and the dependence of this transportation sector on liquid fuels. (NRDC1_81-13)

Comment: <u>Strong Support for Inclusion of AJF in the LCFS</u>

The AJF Producers are highly supportive of the LCFS program and of ARB's proposal to facilitate LCFS credit generation through opt-in participation for AJF uplifted in California. The LCFS has proven to be an effective, market-based program that has driven the development and expanded the supply of low carbon fuels in California. By including low carbon alternative jet fuels in the program, ARB will further expand the supply of less carbon-intense fuels and facilitate attainment of California's greenhouse gas ("GHG") reduction policies. By sending a clear and long-term market signal that AJF is eligible to generate LCFS credits in addition to Renewable Fuel Standard ("RFS") credits ("RINs"), ARB is facilitating investment and development in the decarbonization of the aviation sector. This pioneering work by California is crucial given the anticipated growth of the aviation sector, and the technical and energy intensive demands of this sector. (AJFP1_102-5)

Comment: And to aviation fuels, it represents a major breakthrough in terms of facilitating commercialization out there. (AJFP3_T6-2)

Comment: The proposed regulatory changes cover many aspects of the LCFS. We generally support these changes but would like to in particular express our support for ARB's proposal to allow alternative jet fuel (AJF) to generate LCFS credits as an opt-in fuel. By including low carbon AJF in the program, ARB will stimulate the development

of low carbon fuels for a sector of transportation that currently lacks other effective options for decarbonization. By sending a clear and long-term market signal that AJF is eligible to generate LCFS credits in addition to Renewable Fuel Standard credits (known as RINs), ARB is facilitating investment and development in the de-carbonization of the aviation sector. This pioneering work by California is crucial given the anticipated growth of the aviation sector, the technical and energy intensive demands of this sector, and the dependence of this transportation sector on liquid fuels. (LCFC1_105-4)

Comment: The signatories of this letter support CARB's proposal to allow alternative jet fuel (AJF) to generate LCFS credits as an opt-in fuel. By including low carbon AJF in the program, CARB will stimulate the development of biofuels for a sector of transportation that may lack other effective options for decarbonization and help California attain its greenhouse gas reduction goals. By sending a clear and long-term market signal that AJF is eligible to generate LCFS credits in additional to Renewable Fuel Standard credits (known as RINs), CARB is facilitating investment and development in the de-carbonization of the aviation sector. This pioneering work by California is crucial given the anticipated growth of the aviation sector, the technical and energy intensive demands of this sector, and the dependence of this transportation sector on liquid fuels. (COALITION1_107-4)

Comment: II. <u>A4A Supports CARB's Proposal for AJF as a Credit-Generating Fuel, Without a Mandate</u>

A4A agrees with CARB's general exemption of aircraft fuels from the LCFS mandate. Subjecting aircraft fuels to annual carbon intensity standards would raise federal preemption issues and would not be appropriate given the rigorous jet fuel specifications that make producing jet fuels a "higher hurdle" than producing ground-based fuels. That said, we strongly support CARB's proposal to *incentivize* the use of AJF in aircraft by allowing a voluntary, opt-in credit for such fuels. By promoting the production and use of AJF, CARB would not cross into federal regulatory jurisdiction but rather would provide airlines an opportunity to better support the State's GHG goals. Furthermore, the proposal is fully in line with the U.S. Environmental Protection Agency's approach under the Renewable Fuel Standard (RFS): the RFS explicitly allows for the generation of Renewable Identification Numbers for the production of AJF without mandating the use of any particular volume of AJF. (A4A1_57-4a)

Comment: VI. <u>CARB Has Appropriately Captured the Definition of Alternative Jet Fuel</u>

A4A further supports CARB's proposed definition of alternative jet fuel in Section 95481.[19] Since the LCFS, by definition, is not limited to renewable fuels, the definition of AJF should be sufficiently broad to allow for numerous low carbon alternative jet fuels from either biogenic or non-biogenic feedstocks, including waste industrial gases that would otherwise be emitted. CARB's proposed definition accomplishes this aim, and, therefore, A4A supports the definition as proposed.

[19] CARB ISOR, App. A at § 95481(a)(6).

(A4A1_57-7)

Comment: We also support CARB's proposal to designate the reporting entity as the producer or importer of fuel that is delivered to the storage facility from which it will be uploaded for use in California.[20] A4A believes it is appropriate for CARB to presume that AJF delivered to the pipeline or the airport and designated for use in California will ultimately be uplifted. Furthermore, the designation is consistent with the treatment of other fuels under the LCFS, eliminates potential administrative complexities relating to verifying that fuel sold in California will be ultimately uploaded in the state, and avoids unnecessary reporting of conventional jet fuel for blends. Consequently, we support CARB's proposal as is.

[20] *Id.* at § 95483(a)(1)(C).

(A4A1_57-8)

Comment: The change staff has made to the point of obligation for alternative jet fuel from the initial proposal in 2017 is a significant improvement. Documenting delivery to the airport storage facility rather than to the aircraft itself will greatly simplify tracking and reporting without sacrificing accuracy. (CHEVRON1_112-4)

Comment: WSPA also supports the setting the point of obligation at the airport storage facility. This is a reasonable measure for demonstrating that the fuel was supplied to aircraft in California, without requiring reporting parties to demonstrate delivery to the aircraft themselves. (WSPA2_61-7)

> **Agency Response:** Staff appreciates the support for including alternative jet fuel in the LCFS program as an opt-in credit-generating fuel, maintaining the exemption status of conventional jet fuel, the proposed definition of alternative jet fuel, the designation of the reporting entity as the producer or importer of the fuel, and setting the point of obligation at the airport storage facility.

D-1.2. Multiple Comments: ***Adopt the Proposed Alternative Jet Fuel Provisions***

Comment: We urge you to adopt the proposed amendments to the LCFS that include AJF as an opt-in fuel starting January 1st, 2019. (CAC1_49-3)

Comment: Because crediting AJF in the LCFS would provide needed regulatory incentives for AJF, support the developing California advanced biofuels industry, lower the cost of compliance for obligated parties, and advance the State's environmental and environmental justice goals, A4A strongly urges CARB to adopt the proposed amendments to the LCFS program. (A4A1_57-4)

Comment: Overall, we heartily recommend adoption of the AJF regulatory proposal as proposed and concur with the specifics of the proposed regulatory structure pertaining to the rule. (AJFP1_102-1a)

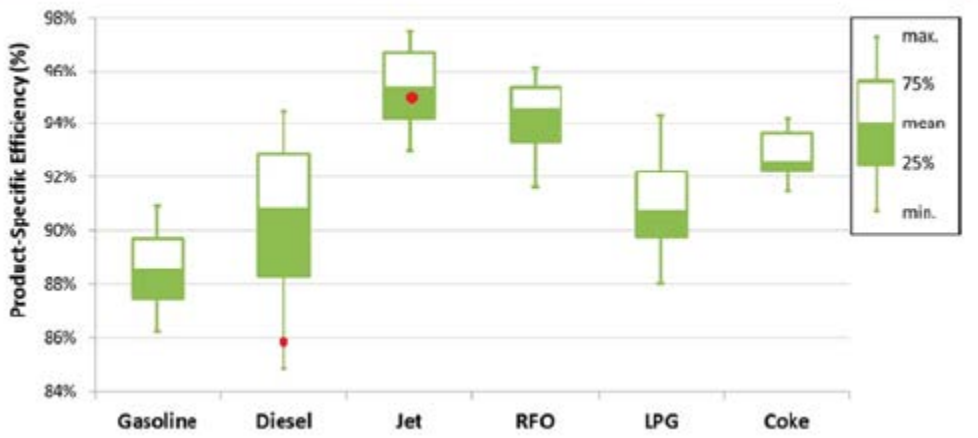
> **Agency Response:** Staff appreciates the encouragement for CARB to adopt the proposed amendment to include AJF as an opt-in fuel.

D-1.3. Multiple Comments: ***Alternative Jet Fuel Baseline***

Comment: Neste however, notes that the proposal **does not properly set the baseline for traditional jet fuel** and staff should revisit on a technical basis to better reflect refinery efficiency in California and on a policy basis to better account for the market differences between jet and diesel production.

First, from a technical perspective, the proposal has incorrectly calculated the carbon intensity score for conventional jet fuel in California. Based on the CA-GREET3.0 Supplemental Document and Tables of Changes (March 6, 2018), the refining efficiencies used for petroleum jet fuel and ULSD in CA-GREET3.0 are 94.9% and 85.87% respectively. The difference between the two numbers - 9.03 percentage points - is a surprisingly large difference between two middle distillate products produced at the same California refineries. These numbers appear to be based on Linear Programming (LP) results for California refineries provided by Argonne. The reference, Elgowainy et al, indicated in the Supplemental Document includes the following table as Figure 7.

Figure 7. Average product shares (by energy) from major processing units in 43 refineries.



The original table does not include the two red dots which have been added here to illustrate the refining efficiencies used for petroleum jet and ULSD in CA GREET3.0. Based on this picture, we can see that ULSD refining efficiency used in CA-GREET3.0 represents a value close to the low-end of the diesel range; whereas the jet refining efficiency is close to the mean value of the jet range. The Elgowainy paper also indicates that the difference between production-weighted average efficiencies of diesel and jet fuel is 4.4 percentage points - which is less than half of the difference between refining efficiencies of petroleum jet and ULSD used in CA-GREET3.0.

Elgowainy et al. also write that “The wide range of diesel efficiencies is attributable to the various pathways for diesel production in refineries. When less diesel yield is desired, the production pathway becomes more efficient because a larger share of the diesel product is produced directly from the distillation tower. However, when more

diesel production is desired, a larger share of the diesel product comes from the hydrocracker (with extensive hydrogen use), the coker, and the FCC units."

Neste asserts that the same could be said for petroleum jet and CARB should provide more information about the sensitivities of the LP model used. For example; what would be the refining efficiency for the marginal petroleum jet, meaning if jet fuel demand would be higher than assumed.

As the refining efficiency is a key parameter when determining the CI of producing a petroleum product, the following changes should be made to CA-GREET3.0 to reflect the impact of changing the refining efficiency. Two different cases are specified below.

Case A:

- Petroleum jet fuel efficiency changed from 94.9 to 91.1% (91.1% is based on a paper by Palou-Rivera et. al, Updates to Petroleum Refining and Upstream Emissions, Argonne National Laboratory 2011.)
- Refinery still gas consumption to reflect the change in efficiency: JetFuel_WTP Cell: C264 Petroleum!$AV120*(1/B$227-1)/(1/Petroleum!$AU$82-1)
- Petcoke consumption to reflect the the change in efficiency: Sheet: JetFuel_WTP Cell: C260 Petroleum!$AV115*(1/B$227-1)/(1/Petroleum!$AU$82-1)

<u>Resulting CI of conventional petroleum jet is 94.04 gCO2e/MJ.</u>

Case B:

- Petroleum jet fuel efficiency from 94.9 to 86.4%, if which case the difference between ULSD at 85.9 and petroleum jet would be 0.5 percentage points. The difference of 0.5% in refining efficiency of diesel and jet is mentioned in the paper by Palou-Rivera et.
- Same changes as in case A regarding still gas and petcoke consumption

<u>Resulting CI of conventional petroleum jet is 99.00 gCO2e/MJ.</u>

Accordingly, CARB has assumed the refinery efficiency attributable to jet fuel to be approximately 5.5% more efficient than real world operations support. This incorrect assumption inappropriately discounts the carbon reduction benefits of AJF compared to the on-road renewable diesel.

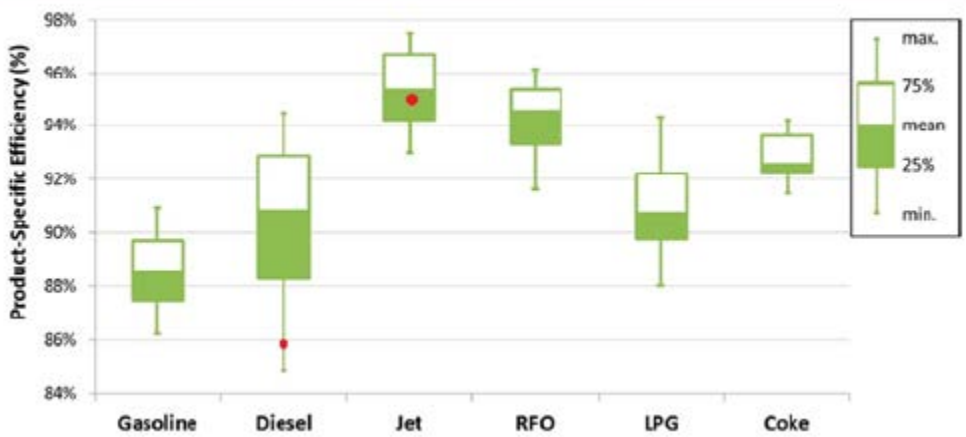
While both cases above show higher baselines with more accurate assumptions about the refining efficiencies, Neste contends that the appropriate refining efficiency for use in setting the AJF baseline should be 91.1% as strongly supported and justified in the background including the paper by Argonne. **<u>The corresponding baseline CI for conventional jet fuel is therefore, 94.04 gCO2e/MJ.</u>** (NESTE1_76-4)

Comment: There is one significant remaining issue pertaining to carbon intensity that justifies further review from both technical and policy perspectives. The technical aspect involves the assumptions underlying the California GREET3.0 ("CA-GREET") carbon intensity ("CI") benchmark score proposed for conventional jet fuel. Based on analysis of jet fuel refining that industry technical experts have developed, it is our conclusion that ARB has assumed the refinery efficiency attributable to conventional jet fuel to be approximately 5.5% more efficient than real world operations support. The practical impact of establishing a benchmark that is 5.5% too low from a technical perspective is that eligible AJF producers will generate 5.5% fewer credits than are technically justified. In a fuel commodity world that operates on basis points, a 5.5% differential is a substantial one. (AJFP1_102-2)

Comment: As noted in the summary, it is our position that from a technical perspective the proposal has incorrectly calculated the carbon intensity score for conventional jet fuel in California. Based on the CA-GREET3.0 Supplemental Document and Tables of Changes (March 6, 2018), the refining efficiencies used for petroleum jet fuel and ultra-low sulfur diesel fuel ("ULSD") in CA-GREET3.0 are 94.9% and 85.87% respectively. The 9.03% difference in efficiency is a substantial difference between two very similar middle distillate products produced at the same California refineries. The efficiency difference is not sufficiently supported in the record to enable a complete response. However, the figures appear to be based on Linear Programming (LP) results for California refineries provided by Argonne. What appears to be the primary technical reference in the ISOR for the refinery efficiency assumptions[2] includes the following table as Figure 7.

[2] ISOR, p. XII-19, footnote 53 provides the following reference from which the table has been extracted: "Energy Efficiency and Greenhouse Gas Emission Intensity of Petroleum Products at U.S. Refineries," Amgad Elgowainy, Jeongwoo Han, Hao Cai, Michael Wang, Grant S. Forman , Vincent B. Divita, May 2014. https://greet.es.anl.gov/publication-energy-efficiency-refineries .

Figure 7. Average product shares (by energy) from major processing units in 43 refineries.



The original table does not include the two red dots which have been added here to illustrate the refining efficiencies used for petroleum jet and ULSD in CA-GREET3.0. This figure illustrates that the ULSD refining efficiency used to establish the CI value for conventional jet fuel represents a value close to the low-end of the diesel range;

whereas the jet refining efficiency is close to the mean value of the jet range. The same underlying Argonne technical paper also indicates that the difference between production-weighted average efficiencies of diesel and jet fuel is 4.4%. In contrast, ARB selected a difference of 9.03% for its modeling in CA-GREET3.0, more than double the difference in the Argonne GREET paper.

In the underlying technical paper, Elgowainy et al. state that "The wide range of diesel efficiencies is attributable to the various pathways for diesel production in refineries. When less diesel yield is desired, the production pathway becomes more efficient because a larger share of the diesel product is produced directly from the distillation tower. However, when more diesel production is desired, a larger share of the diesel product comes from the hydrocracker (with extensive hydrogen use), the coker, and the FCC units."[3]

[3] "Energy Efficiency and Greenhouse Gas Emission Intensity of Petroleum Products at U.S. Refineries," Amgad Elgowainy, Jeongwoo Han, Hao Cai, Michael Wang, Grant S. Forman , Vincent B. Divita, May 2014. https://greet.es.anl.gov/publication-energy-efficiency-refineries .

This same reasoning appears equally applicable to petroleum jet. To better explain its technical approach, ARB should provide more information about the sensitivities of the LP model used. For example, ARB should indicate the refining efficiency for the marginal petroleum jet in the event that jet fuel demand is higher than assumed.

As the refining efficiency is a key parameter when determining the CI of producing a petroleum product, the following changes should be made to CA--GREET3.0 to reflect the impact of a more accurate refining efficiency assumption. Two different cases are specified below.

Case A:

- Petroleum jet fuel efficiency changed from 94.9 to 91.1%.[4]
- Refinery still gas consumption to reflect the change in efficiency.[5]
- Petcoke consumption to reflect the the change in efficiency[6]

[4] The figure of 91.1% is based on a paper by Palou-Rivera et. al, Updates to Petroleum Refining and Upstream Emissions, Argonne National Laboratory 2011. https://greet.es.anl.gov/files/petroleum

[5] The CA-GREET3.0 spreadsheet reference here is JetFuel_WTP Cell: C264 Petroleum!$AV120*(1/B$227-1)/(1/Petroleum!$AU$82-1)

[6] The CA-GREET3.0 reference is Sheet: JetFuel_WTP Cell: C260 Petroleum!$AV115*(1/B$227-1)/(1/Petroleum!$AU$82-1)

<u>Resulting CI of conventional petroleum jet in 2010 is 94.04 gCO2e/MJ.</u>

Case B:

- Petroleum jet fuel efficiency from 94.9 to 86.4%, if which case the difference between ULSD at 85.9 and petroleum jet would be 0.5 percentage points. The difference of 0.5% in refining efficiency of diesel and jet is mentioned in the paper by Palou-Rivera et al.

- Same changes as in case A regarding still gas and petcoke consumption

Resulting CI of conventional petroleum jet in 2010 is 99.00 gCO2e/MJ.

Accordingly, ARB has assumed the refinery efficiency attributable to jet fuel to be approximately 5.5% more efficient than real world operations support resulting in a 2010 CI score of 89.84. This incorrect assumption inappropriately discounts the CI of jet fuel as compared to on-road diesel resulting in lesser credit generation opportunities for AJF. While both cases illustrated rely upon reasonable assumptions about the real world refining efficiencies, the AJF Producers respectfully submit that the appropriate refining efficiency for use in setting the AJF baseline should be 91.1%. This approach is illustrated by Case A and is strongly supported and justified in the technical literature including the paper cited by ARB in the ISOR. (AJFP1_102-6)

Comment: Although LCFS credits would significantly improve the economics of AJF production, we would like to propose revisions to the proposed carbon intensity (CI) benchmark for conventional jet fuel for AJF credit generation purposes.

First, we suggest reconsidering the proposed 2010 value for conventional jet fuel. Recent analyses by various parties suggest that the 89.75 g CO_2e/MJ value from Argonne National Laboratory's GREET model may be too low because it does not take into account refinery efficiency in California. More recent analyses submitted by AJF producers looking at California jet fuel in suggest that a value of 94.04 g CO_2e/MJ would be more appropriate. (UNITED1_B12-2)

Comment: III. A4A Urges CARB to Adjust the 2010 Conventional Jet Fuel Baseline Upward

We suggest that CARB revisit the proposed 2010 value for the conventional jet fuel baseline, which currently is proposed to be set at 89.75 g CO_2e/MJ, to more accurately reflect refinery efficiency in California. Several recent analyses indicate that the jet fuel refining efficiency assumption in the California GREET model is overly optimistic. For example, the "AJF Producers" group has prepared and submitted analyses under the CA-GREET 3.0 spreadsheet model demonstrating that 94.04 g CO_2e/MJ would be an appropriate carbon intensity value for AJF.[8] We urge CARB to appropriately adjust the efficiency assumption consistent with these analyses, which would result in an upward adjustment relative to the proposed 2010 value for the conventional jet fuel baseline.

[8] Specifically, the AJF Producers' analysis demonstrates that the appropriate refining efficiency for use in setting the AJF baseline should be 91.1%, which results in a corresponding baseline carbon intensity for conventional jet fuel at 94.04 gCO_2e/MJ. We also note that previous CARB technical work fully supported a jet fuel baseline at 93.3 g CO_2e/MJ, which CARB specified for use in the above-mentioned modeling analysis conducted by NREL. *See* NREL presentation at 18 (noting CARB specified CI values of 93.3, 102, and 99.8 for petroleum jet, diesel, and gasoline, respectively).

(A4A1_57-5)

Comment: 7. Increase the baseline carbon intensity value for fossil jet fuel

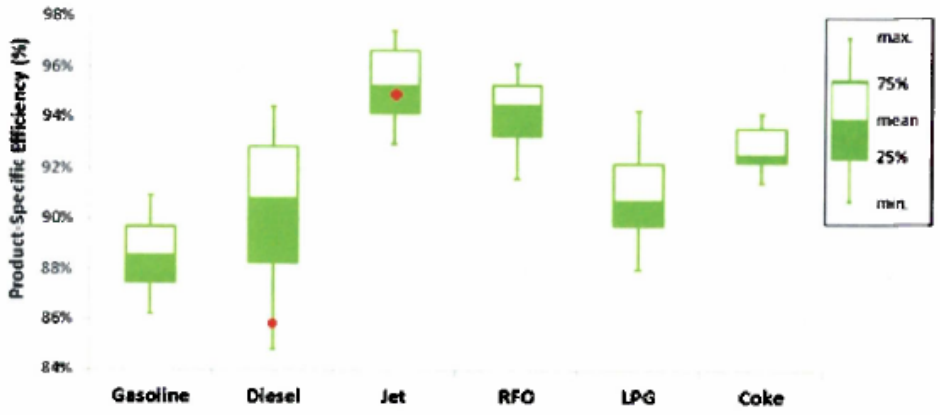
We concur with the AJF Producers' assessment that the fossil jet fuel carbon intensity baseline is overly optimistic in its assessment of the processing required to produce jet fuel. (LANZATECH1_77-9)

Comment:

✓ Not the Correct Technical Determination

Technical (Argonne GREET Table)

Figure 7. Average product shares (by energy) from major processing units in 43 refineries.



Refining Efficiency

- Jet Assumed Efficient
- Diesel Assumed Inefficient
- Inefficiency= More Credits

(AJFP2_B1-2)

Comment: We would also like to call attention to the surprisingly low carbon intensity CI selected for the petroleum jet fuel base. This value must presume the simplest (and lowest energy) jet fuel manufacturing process, which is distillation of crude oil, followed by "sweetening" (sulfur mercaptan removal) in a Merox unit and finishing with clay treating https://www.clariant.com/en/Business-Units/Functional-Minerals/Kerosene-and-Jet-Fuel-Purification to remove contaminants that create problems meeting JFTOT, MSEP and WISM specifications of the ASTM D1655 Standard Specification for Aviation Turbine Fuels. This is the process that Paramount Petroleum (our currently closed co-sited refinery) used in their petroleum refining process for manufacturing jet fuel until

a jet fuel hydrotreating process was added in 2005. It is believed that this was the last California refinery manufacturing jet fuel with a low energy (CI) process.

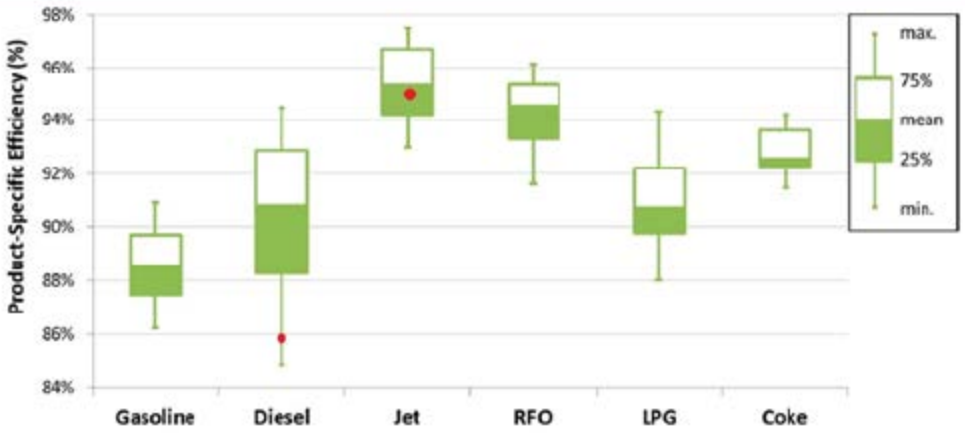
We believe that all jet fuel producers in California in 2010, the LCFS base year, used much more sophisticated and complex processes and refineries for converting crude oil to jet fuel (in addition to simple crude oil distillation). These processes include vacuum distillation, vacuum gasoil hydrotreating, vacuum and coker gasoil hydrocracking, coking, and jet/distillate hydrotreating. Many of these processes require hydrogen that must be also be manufactured or purchased with additional energy (and CI) requirements.

The previous Linear Programming (LP) models that have been developed to simulate the U.S. and California refinery operations (for EIA, Argonne National Laboratory, and others) to date have not been designed to focus on jet fuel production, but rather on motor fuels production and don't accurately model the specifics of California refinery operation. As a result, it is expected that they have not been "tuned" to properly track the jet fuel boiling range refinery stream qualities and their process unit flow volumes to the jet fuel blending pool. This additional model verification and tuning is needed to properly model and match historical production and quality and arrive at the expected higher jet fuel CI. We suggest that this model verification and "tuning" exercise should be considered in the future to provide a solid basis for the 2010 base jet fuel CI. (ALTAIR1_B13-2)

Comment: However, we urge you to consider revisions that we and the AJF producers proposed in our written comments regarding the carbon intensity provisions that would apply to AJF.

First, the 2010 CI values for the conventional jet fuel baseline should reflect refinery efficiency in California. (UAA4A1_T36-2)

> **Agency Response:** The conventional jet fuel refining efficiency in CA GREET3.0 model is 94.9 percent, which represents California-specific refineries for the data year 2010; it was calculated from Linear Programming (LP) modeling analysis and was adjusted based on the EIA's Annual Energy Outlook. The LP modeling results also include the input energy shares for conventional jet fuel production. The same LP modeling approach was also applied to generate the refining efficiency and the input energy share of CARBOB and California Ultra-Low Sulfur Diesel (ULSD) in CA-GREET3.0. In comparison, the petroleum refining efficiencies appeared in CA-GREET2.0 represented the weighted average of the PADD 5 refineries and the modeling effort for this version of the GREET did not differentiate jet fuel from other fuel products.



The figure above was cited in the comments to illustrate the difference in refining efficiencies between diesel and jet fuel. The original source of this figure, Elgowainy et al. (2014), indicates this figure represents the U.S. average (43 refineries, data year 2010) refining efficiencies. In contrast, all refining efficiencies implemented in CA-GREET3.0 represent California-specific refineries (data year 2010). Similarly, comments suggest a refining efficiency of 91.1 percent should be used for the baseline jet fuel CI calculation, "as strongly supported and justified" by another reference from Argonne (Palou-Rivera et al., 2011); however, the 91.1 percent value reported in this 2011 reference represents an U.S. average value and not specific to California refineries. Although fuel specifications for jet fuel are driven by national standards, refinery configurations, operational requirements dictated by stringent fuel specifications for gasoline and diesel blend stocks and the basket of crude oil used by California refineries are significantly different. A simple extrapolation of U.S. average refinery operational data is, therefore, not applicable to model California refineries; the modeling of California refineries requires a separate exercise.

Secondly, in the same study from which this figure is cited, the conventional U.S. fuel specifications were applied to both "Diesel" and "Jet". However, in CA-GREET3.0, the sulfur content of the U.S. conventional diesel is 200 ppm (by weight), whereas California ULSD is 11 ppm (by weight). Stringent specifications for sulfur in ULSD leads to lower refining efficiency compared to U.S. conventional diesel. The assumption that "U.S. conventional diesel" and "CA ULSD" could share the same fuel specifications is, therefore, not appropriate.

Thirdly, the Elgowainy et al. (2014) reference reports a weighted-average jet fuel efficiency of 95.3 percent and "that the difference between production-weighted average efficiencies of diesel and jet fuel is 4.4 percentage points"; however, in Palou-Rivera et al. study (2011), which was published by the same group at Argonne using an early version of the LP model, the weighted-average jet fuel efficiency was set at 91.1 percent and the difference between jet and diesel was arbitrarily set at 0.5 percent because the LP model at the time could not differentiate various refinery products. Therefore, staff believes the

California-specific LP results better represent the in-state refining process than the U.S. average, and simply using the difference between jet and diesel as a parameter in the comments is not a scientifically-sound measurement.

Moreover, comments attempted to modify the values of petcoke and refinery still gas as intermediate energy in the conventional jet fuel refining process. Currently in CA-GREET3.0, values of these two parameters were generated from the LP model using California-specific data, as mentioned earlier in the staff's response. This method is also consistent with the CARBOB and the California ULSD modeled in CA-GREET3.0. The formulae provided in the comments were cited and only valid in CA-GREET2.0, where petcoke and refinery still gas consumption of the jet fuel refining was estimated based on those from diesel production, given the previous LP modeling results could not differentiate various refining products. CARB staff believes the current values of these two intermediates are more representative of the conventional jet fuel production in California than the values provided in the comments and the methodology is consistent with other baseline fuels in CA-GREET3.0.

The comments also attempted to reduce the jet fuel refining efficiency even further by adding 0.5 percent to the efficiency of the California ULSD (85.9 percent). As stated earlier in the staff's response, this 0.5 percent addition was a previous arbitrary assumption and was used for the U.S.-average practice. CARB staff believes such an attempt from the comments lacks sufficient scientific or industrial evidence. Additionally, several comments indicate that the 94.9 percent conventional jet fuel refining efficiency is "approximately 5.5% more efficient than real world operations support", but fail to provide additional information (such as the number of data points, the data year, the location of the surveyed refineries, and the statistics) about the "real world operation" for staff to conduct further analysis.

In addition to the refining process, the comments indicate that low-sulfur jet should be considered as the baseline/benchmark fuel. After consulting the California-based petroleum refineries, experts from the local and the federal transportation agencies, and scholars whose studies focus on the environmental and the economic impacts of the jet fuel quality, CARB staff proposes that the conventional jet fuel with the maximum sulfur content at 700 ppm (by weight) should remain as the baseline jet fuel pathway.

Comments also request CARB to either provide detailed information of the LP model or perform the sensitivity analysis of the LP model. Staff has forwarded this request to the Argonne National Laboratory, who provided CARB the LP modeling results based on the proprietary data from refineries in California. Argonne has Nondisclosure Agreements with the participants who provided facility-specific data and is not able to release these data to the public. In the

publications release by Argonne,[3,4] however, similar verification analysis of the LP modeling results for both the U.S. average (43 refineries) and various PADD areas was conducted. Staff acknowledges the additional description of the jet fuel refining process brought up by many comments; however, without detailed data, model, and assumptions, staff was unable to confirm the validity of the asserted description or to evaluate the key parameters (i.e., energy efficiency, process fuel shares, modeling year) for the life cycle analysis.

D-1.4. Multiple Comments: *Alternative Jet Fuel Benchmarks*

Comment: IV. The Proposal to Have Decreasing Carbon Intensity Benchmarks for AJF Should Be Revised

Table 3 of the CARB's Proposed Regulation Order provides decreasing carbon intensity benchmarks for 2019–2030 for fuels used as substitutes for conventional jet fuel. According to the ISOR, "the AJF annual benchmarks are anchored to the 2010 baseline [carbon intensity] for conventional jet fuel and incorporate the same annual percent reductions as the benchmarks for gasoline and diesel."[9] Based on this, CARB proposes to adjust the proposed 2010 carbon intensity baseline of 89.84 g CO_2e/MJ for jet fuel to 84.23 g CO_2e/MJ for the 2019 start date of the proposed opt-in credit and decrease the carbon intensity further thereafter. A4A does not believe it is appropriate for CARB to apply decreasing carbon intensity benchmarks to jet fuel and urges CARB to reconsider this aspect of its proposed amendments.

[9] CARB ISOR at II-5.

The LCFS and its proposed amendments have no regulatory mandate to reduce the carbon intensity of jet fuel over time unlike the requirements for diesel and gasoline to reduce their respective carbon intensities 7% and 8% by 2020 and 20% for both fuels by 2030.[10] Removing the decreasing carbon intensity benchmarks for jet fuel would be consistent with the fuel's existing exemption and would appropriately recognize the difference between CARB's regulatory authority over diesel and gasoline and its limited authority to offer incentives to reduce aviation emissions.[11] Notably, crediting AJF on an opt-in basis in the LCFS still assures environmental benefit even with a static baseline relative to conventional jet fuel, as the AJF would have to have confirmed emissions reductions relative to that baseline to be credited.

[10] CARB ISOR, App. A at § 95484(b), (c).

[11] As noted above, California is preempted from regulating jet fuel and therefore has no legal basis to require carbon intensity reductions from the conventional jet fuel pool despite its authority to incentivize AJF through a voluntary credit as proposed.

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[3] Cai H, Han J, Forman G, Divita V, Elgowainy A, Wang M. 2013. Analysis of Petroleum Refining Energy Efficiency of U.S. Refineries. Technical Report. Argonne National Laboratory. https://greet.es.anl.gov/publication-petroleum-eff-13

[4] Forman GS, Divita VB, Han J, Cai H, Elgowainy A, Wang M. 2014. U.S. Refinery Efficiency: Impacts Analysis and Implications for Fuel Carbon Policy Implementation. Environmental Science & Technology. 48, 7625-7633

A4A understands that CARB is considering decreasing the carbon intensity benchmark over time for AJF out of a potential concern by some that the absence of a decreasing benchmark could distort the alternative fuels market in favor of AJF over similar and competing ground transportation fuels like renewable diesel. To the contrary, however, decreasing the carbon intensity benchmark for jet fuel is not needed to prevent market distortions given the many factors that will still place AJF at a market disadvantage, and the fact that AJF production also necessarily results in the production of other fuels within a product slate.

There are at least three reasons why AJF is and is expected to remain at a market disadvantage relative to alternative ground transportation fuels. First, outside market forces encourage renewable diesel production over AJF. The chief market force favoring diesel over jet fuel is the higher price historically commanded for diesel fuel in the spot market. Data from the U.S. Energy Information Administration (EIA) indicates that the spot price for jet fuel has historically been below the price of diesel, and the EIA anticipates this market dynamic to continue for the foreseeable future, chiefly due to tighter sulfur limits on diesel fuel (see Figure 2 below).[12] Average annual data on the prices of diesel and jet fuel available in Los Angeles summarized below in Figure 3 also demonstrate that the price of diesel in California generally exceeds the jet fuel price.[13]

[12] See U.S. Energy Information Administration spot price data at https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm; *see also* EIA, *The Flight Paths for Biojet Fuel* at 3 (noting that "non-petroleum hydrocarbons that can go into jet fuel can also be blended into diesel fuel or heating oil, both of which are projected to sell for higher prices than jet fuel in the future."). *See also*, International Renewable Energy Agency, *Biofuels for Aviation* at 5 (noting that producers are focused on producing renewable diesel, which has a larger market and higher sales price).

[13] Data provided by Bloomberg.

Figure 2. EIA estimates and projections of U.S. jet fuel and distillate fuel prices, 2000—2040

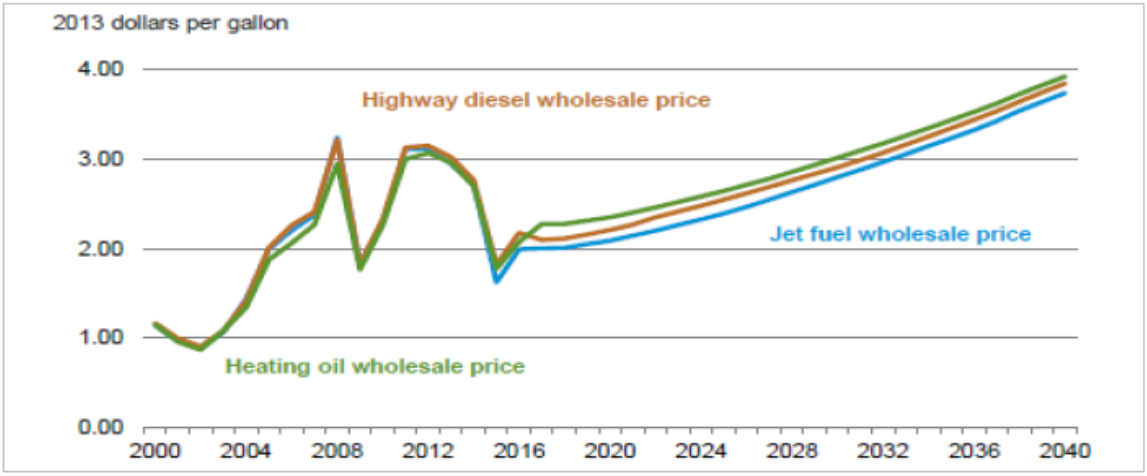
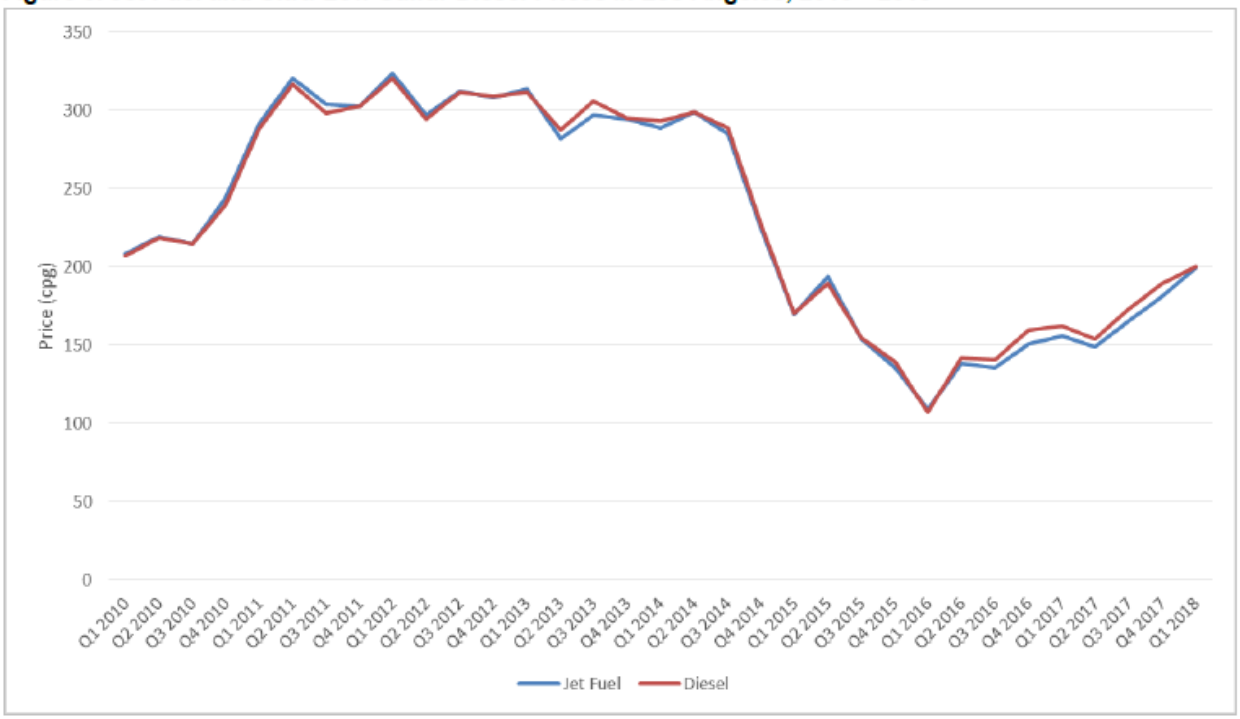


Figure 3. Jet Fuel and Ultra-Low Sulfur Diesel Prices in Los Angeles, 2010—2018



Second, diesel substitutes benefit from the added value associated with diesel's inclusion in the California cap and trade program (currently $15/ton or roughly 15 cents per gallon of diesel) which promotes renewable diesel supply. This pricing benefit and the higher handling costs associated with meeting strict aviation fuel specifications make jet fuel a less economical option.

Third, the significant differences between the proposed 2010 baselines of 89.84 g CO_2e/MJ for jet fuel, which CARB proposes to adjust to 84.23 g CO_2e/MJ for the 2019 start date of the proposed opt-in—or even the revised baseline of 94.04 g CO_2e/MJ that the AJF Fuel Producers and A4A assert—and 100.95 g CO_2e/MJ for diesel further favor diesel. In fact, the proposed jet fuel baseline is already significantly below the current carbon intensity standard for diesel of 96.91 g CO^2e/MJ[14] and would remain below the diesel standard for years. CARB should consider alternative benchmarks that would not unintentionally memorialize existing structural disincentives for the production of AJF.

[14] CARB ISOR, App. A at § 95484(c) (carbon intensity for 2018).

A4A therefore suggests that CARB use a static carbon intensity benchmark instead. Using a static baseline would recognize jet fuel's status as an exempt fuel receiving opt-in credit for AJF use. It would also maximize CARB's ability to generate emissions reductions in a sector where CARB otherwise does not have regulatory authority.

Furthermore, the question of parity between a static jet fuel baseline at the level currently proposed and the diesel carbon intensity baseline would not even become an issue until later years (for example, 2024 or 2027, depending on what initial baseline is used for jet fuel). And, even then, the other market forces disadvantaging AJF would

remain. Moreover, the fact that diesel is necessarily coproduced with AJF, often with diesel in a much higher ratio, assures its prominence in the market. CARB has recognized that it is unlikely that promotion of AJF will divert investment away from diesel. In its ISOR, some stakeholders expressed concern that "if supply of low carbon biomass feedstocks is limited, AJF production may compete with production and on-road use of biomass-based diesels. . . ."[15] However, CARB "Staff believes this is unlikely and that a more likely outcome of the Proposed Amendments' inclusion of AJF is that more facilities would be built that co-produce both biomass-based diesel and AJF . . . ."[16] We urge CARB to reinforce this finding based on the above information.

[15] CARB ISOR, App. D: Draft Environmental Analysis at 66–67.

[16] *Id.*

For these reasons, CARB is perfectly justified in maintaining a static carbon intensity baseline for AJF as A4A suggests. Nonetheless, should CARB not do so, it should at least adopt a static baseline for jet fuel until such time that the jet fuel carbon intensity baseline meets the diesel carbon intensity benchmark, at which time the jet fuel carbon intensity benchmarks would decrease in line with the diesel carbon intensity benchmarks. This would ensure that AJF never commands a greater LCFS credit than renewable diesel and would promote market parity and the fuel neutrality goals of CARB.

A4A supports CARB's intent to eliminate potential market distortions under the LCFS. Indeed, eliminating market distortions is precisely why A4A has consistently urged CARB to include AJF as an opt-in fuel under the LCFS. However, we urge CARB to closely examine options that would protect against market distortions while maximizing the LCFS market signal and the emissions reduction potential of the program. Consequently, we urge CARB to reconsider its carbon intensity benchmarks for jet fuel in favor of one of the two approaches we have outlined above, which reflect CARB's own regulatory authority and policy goals. (A4A1_57-6)

Comment: REG thinks the benchmark for alternative jet fuel being lower than diesel and gasoline will prevent this new opt-in fuel from taking off. CARB should rethink its approach in this area and better affirm its support of the alternative marketplace. (REG1_88-10)

Comment: The closely related policy issues pertain to the starting point and the shape of the carbon intensity curve that ARB establishes for AJF. In particular, ARB has proposed a CI curve with the same downward slope as the petroleum diesel curve even though ARB does not have regulatory authority over the CI of jet fuel. In addition, ARB has proposed a CI curve that "catches up with" the decline in the diesel curve even though AJF could not generate credits during the first eight years of the LCFS program. As a net result of these two policy decisions coupled with the unfavorable CI determination, ARB is proposing CI benchmarks for AJF that are 11% below the diesel benchmarks through 2030. If approved, the resulting Table 3 of the proposed rule would therefore result in 11% less credit generation per gallon for AJF than on-road renewable diesel fuel.

It is our impression that ARB has exercised both its technical and its policy discretion to disfavor AJF from a crediting perspective out of an abundance of caution. The underlying concern identified in the initial statement of reasons is the potential risk of diversion of fuel production from the on-road sector (renewable diesel or "RD") to the aviation sector (alternative jet fuel or "AJF").[1] In response to this concern, the decision has been taken to set the CI benchmarks for AJF in a manner that discounts credit generation opportunities so that not a single drop of California's on-road RD fuel supply is diverted into the aviation market.

[1] As noted in the ISOR, some stakeholders expressed concern that "if supply of low carbon biomass feedstocks is limited, AJF production may compete with production and on-road use of biomass-based diesels…" ARB ISOR, Appendix D: Draft Environmental Analysis at 66-67.

We respect the diligent environmental stewardship that underlies this approach and do not question the underlying objective. However, there is an existing economic framework that very effectively protects California's on-road renewable diesel fuel supply. This economic framework consists of a durable combination of factors including production economics, fuel specifications, market forces, California climate policies, and the federal Renewable Fuel Standard (RFS). This comment describes and explains these various factors and provides empirical data to substantiate the economic value of each factor. Taken as a whole, these factors demonstrate that AJF production will remain significantly disadvantaged compared to on-road fuel even after AJF becomes eligible to generate LCFS credits. We request that ARB closely examine this economic framework; recognize that it provides ample protection to California's renewable diesel supply; and proceed to establish LCFS crediting parity for AJF production.

…

After setting the baseline CI for conventional jet fuel for 2010, the additional step that ARB utilized in setting the CI benchmark scores for AJF for 2019 and subsequent years was to further discount the 2010 CI score by 6.25%. This discount is equivalent to the CI reductions imposed on diesel fuel from 2011-2018. As established by Table 3 of the proposed regulation, this results in a CI benchmark score of 84.23 for 2019 for crediting purposes with a decline of CI to 71.87 established for 2030 and subsequent years.

…

<u>Establishing the Optimal Benchmark for AJF Credit Generation</u>

ARB has acknowledged that its authority is markedly different in the aviation sector as compared to the on-road transportation sector. As noted in the ISOR,

> *Subjecting aircraft fuels to annual carbon intensity standards would raise federal preemption issues. However, CARB has the authority to amend the LCFS regulations to create incentives to promote the use of low carbon fuels in aircraft by allowing credit for such fuels. By promoting the voluntary production and use of alternative jet fuel, CARB would not be regulating aircraft fuels, but rather would*

simply be creating opportunities for airlines to better support California's GHG objectives.[8]

[8] CARB ISOR at III-30.

Recognizing the federal preemption issues, ARB is not establishing mandatory declining standards for the CI of conventional jet fuel and aviation gasoline in California. ARB is instead providing an opt-in LCFS credit generation opportunity for AJF that is intended to have the salutary effect of achieving GHG reductions in the unregulated aviation sector. While the benchmark scores in the CI tables applicable to gasoline (Table 1) and diesel fuel (Table 2) set the annual compliance standards for regulated parties and establish the rate of credit generation for low carbon fuel producers, Table 3 for conventional jet fuel only establishes the rate of credit generation for AJF producers.

Within the regulatory context of opt-in crediting, ARB has broad discretion regarding the benchmarks it sets for credit generation purposes. The approach that ARB is proposing is established by Table 3 entitled, "LCFS Carbon Intensity Benchmarks for 2019 to 2030 for Fuels Used as a Substitute for Conventional Jet Fuel." As described by the ISOR, "the AJF annual benchmarks are anchored to the 2010 baseline for conventional jet fuel and incorporate the same annual percent reductions as the benchmarks for gasoline and diesel."[9] Based on this approach coupled with the underlying CA-GREET analysis, CARB proposes to adjust the 2010 baseline of 89.84 g CO2e/MJ for jet fuel to 84.23 g CO2e/MJ for the 2019 start date of proposed the opt-in and decrease it further thereafter. Regarding the rationale for its methods of setting the carbon intensity benchmarks for AJF, the ISOR states,

[9] CARB ISOR at II-5.

"To maintain consistency with the annual carbon intensity benchmark for diesel and gasoline and to create a level playing field with ground transportation fuels, staff is proposing that the annual carbon intensity benchmarks for alternative jet fuel incorporate the same annual percent reduction as the annual carbon intensity benchmarks for gasoline and diesel for 2019 through 2030."[10]

[10] CARB ISOR, at III-46.

However, given ARB' lack of authority to regulate jet fuel, consistency here is misplaced. From a policy design perspective, there are several approaches that ARB could have taken that would have yielded a better policy outcome and <u>would have been more consistent with ARB's regulatory authority</u>. One approach discussed during the rulemaking process would be to utilize the existing diesel curve contained in Table 2 as the applicable benchmark. This approach would place AJF credit generation on precisely the same footing as on-road renewable diesel credit generation. It would also recognize the realities of the fuel marketplace. As ARB noted in the ISOR,

"Second, because AJF and renewable diesel (RD) are often produced in the same facility using the same feedstock, inclusion of AJF may lead to increased investment in such facilities, thereby increasing the production of both alternative fuels."[11]

[11] CARB ISOR, at II-5.

Given that AJF and RD are often produced in the same facility, establishing the same benchmark for the two fuels would have provided both fuels with the same LCFS credit generation opportunities. Such an approach would not favor AJF production over RD production, and would not present any risk of market distortion. The AJF Producers support such an even-handed crediting mechanism, and we continue to view it as a preferred solution to the proposal.

Another benchmarking approach that would be more consistent with ARB's regulatory authority would be to establish a fixed benchmark standard for conventional jet fuel. This would be consistent with conventional jet fuel's LCFS exemption and would appropriately recognize the difference between CARB's regulatory authority over diesel and gasoline and its authority to provide a voluntary incentive in the aviation sector. Rather than a curve, such an approach would establish a fixed benchmark. It would logically be fixed at the CA-GREET 3.0 carbon intensity score that ARB determines for conventional jet fuel for 2010. As discussed in the technical section of this comment, the AJF Producers submit that the appropriate 2010 CI score for conventional jet is 94.04, whereas ARB has proposed 89.84. ARB has further proposed to reduce its benchmark of 89.84 by 6.25% which would result in a CI benchmark of 84.23 for 2019.

While a fixed benchmark score is justified from a regulatory authority perspective, the AJF Producers recognize that ARB is concerned with an LCFS crediting mechanism that provides relatively more LCFS credits to alternative jet fuel than to on-road renewable diesel. We therefore would also support a hybrid approach that commences with a benchmark based on conventional jet fuel's CI score determined but declines in tandem with the diesel standard in Table 2 beginning when the CI standard for diesel fuel reaches its level.

- To illustrate this hybrid approach using the 2019 CI benchmark that ARB has proposed in Table 3 of 84.23, the benchmark for AJF would remain at 84.23 through 2027. Beginning in 2028 when the declining CI curve for diesel fuel goes below this CI level and in subsequent years, the CI benchmark for diesel fuel would also be the benchmark for AJF.
- To illustrate this hybrid approach using the CI score that is established by the refinery efficiency rating described in Case A of this comment (94.04) and without a 6.25% decline, the benchmark for AJF would be 94.04 in 2019, then would begin declining with the diesel CI score beginning in 2020 and for all subsequent years.

…

As currently proposed, the LCFS will slant another long-term policy in favor of renewable diesel over alternative jet fuel. Specifically, the CI benchmark values for jet in Table 3 establish an 11% crediting disadvantage compared to the diesel benchmark values contained in Table 2. In today's market, this 11% disadvantage translates in economic terms to a $0.16 discount in LCFS credits generated. Thus the production of alternative jet fuel will remain economically disadvantaged in yet another policy program even with the recognized benefit of LCFS program inclusion.

It is within this landscape that the technical and policy issues pertaining to carbon intensity and LCFS credit generation should be evaluated. The AJF Producers recognize both the general LCFS principle of fuel neutrality and the importance of RD in fulfilling California's climate and air quality goals. We therefore request a revised CI table for jet fuel that immediately establishes crediting parity between AJF and RD fuel, or moves to crediting parity between the two fuels as quickly as possible. (AJFP1_102-3)

Comment: As previously noted, one concern expressed in the ISOR is the possibility of diverting production capacity from renewable diesel to AJF production. The following economic factors are described and quantified in today's market to illustrate that renewable diesel is well-protected against any such risk.

<u>Economic Factors Applicable to the AJF Market</u>

The economic factors applicable to the AJF Market that place AJF production at a structural disadvantage to on-road renewable diesel production are as follows:

1. Producers forecast less revenue from sales of alternative jet fuel than renewable diesel because jet fuel has historically sold at a discount to on-road diesel in the California market and future projections predict this trend will continue.
2. Due to the more stringent cold flow specification for jet fuel, alternative jet fuel requires more intensive processing than does on-road renewable diesel. Petroleum jet is relatively less burdened in meeting the jet specifications due to the inherent differences between fossil crude feedstocks and renewable jet feedstocks.
3. Jet fuel is not burdened at the rack by the cost of cap and trade allowances as is petroleum diesel. In today's market, this provides renewable diesel with an effective .15/gallon price discount to petroleum diesel that alternative jet fuel will not receive.
4. Conventional jet fuel pricing is also not burdened with the LCFS compliance cost that is assessed at the rack for conventional diesel fuel resulting in an effective .07/gallon price discount to petroleum diesel in today's market that alternative jet fuel will not receive.
5. Under the federal Renewable Fuel Standard (RFS), AJF receives relatively fewer RINs than on-road diesel with renewable diesel generating 1.7 RINs per gallon and renewable jet fuel generating 1.6 RINs per gallon. This results in a 6% discount on RIN generation representing .06/gallon less incentive per gallon in today's market.

Each of these economic factors is explained in additional detail in the following sections, with empirical support provided for each factor. Finally, the cumulative economic impact of these factors is considered with reference to the production of alternative jet fuel as compared to on-road renewable diesel. From a technology standpoint, this discussion focuses solely on alternative jet fuel that is produced via hydroprocessing which is the

production process utilized by AltAir Fuels and Neste. This focus is necessary at this stage of industry development because, "Hydroprocessing technologies using vegetable and waste oils represent the only conversion pathways that are ready for large scale deployment (Leuphana 2011)."[12]

[12] National Renewable Energy Laboratory, Review of Biojet Fuel Conversion Technologies, Wei-Cheng Wang, Ling Tao, Jennifer Markham, Yanan Zhang, Eric Tan, Liaw Batan, Ethan Warner, and Mary Biddy Prepared under Task No. BB14.4420, at p. 6, available at https://www.nrel.gov/docs/fy16osti/66291.pdf .

1. Producers forecast less revenue from sales of alternative jet fuel than renewable diesel because jet fuel has historically sold at a discount to on-road diesel in the California market and future projections predict this trend will continue.

First, outside market forces encourage renewable diesel production over AJF. The chief market force favoring diesel over jet fuel is the higher price historically commanded for diesel fuel in the spot market. Data from the U.S. Energy Information Administration (EIA) indicates that the spot price for jet fuel has historically been below the price of diesel, and the EIA anticipates this market dynamic to continue for the foreseeable future, chiefly due to tighter sulfur limits on diesel fuel (see Figure 1 below).[13] Average annual data on the prices of diesel and jet fuel available in Los Angeles summarized below in Figure 2 also demonstrate that the price of diesel in California generally exceeds the jet fuel price.[14]

[13] See U.S. Energy Information Administration spot price data at https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm; *see also* EIA, The Flight Paths for Biojet Fuel at 3 (noting that "non-petroleum hydrocarbons that can go into jet fuel can also be blended into diesel fuel or heating oil, both of which are projected to sell for higher prices than jet fuel in the future."). *See also*, International Renewable Energy Agency, Biofuels for Aviation at 5 (noting that producers are focused on producing renewable diesel, which has a larger market and higher sales price).

[14] Data provided by Bloomberg.

Figure 1. EIA estimates and projections of U.S. jet fuel and distillate fuel prices, 2000—2040

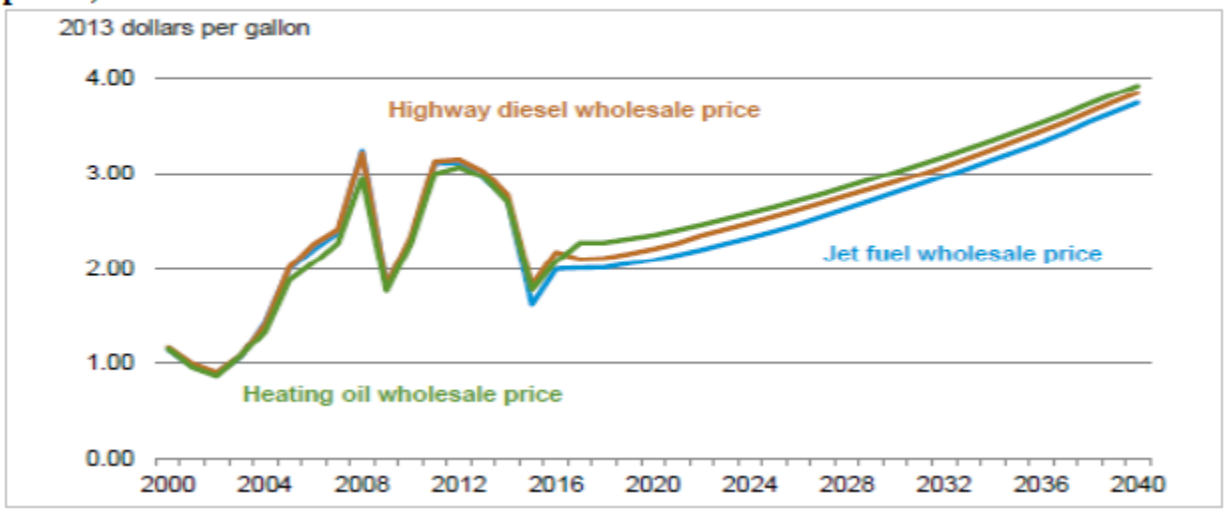
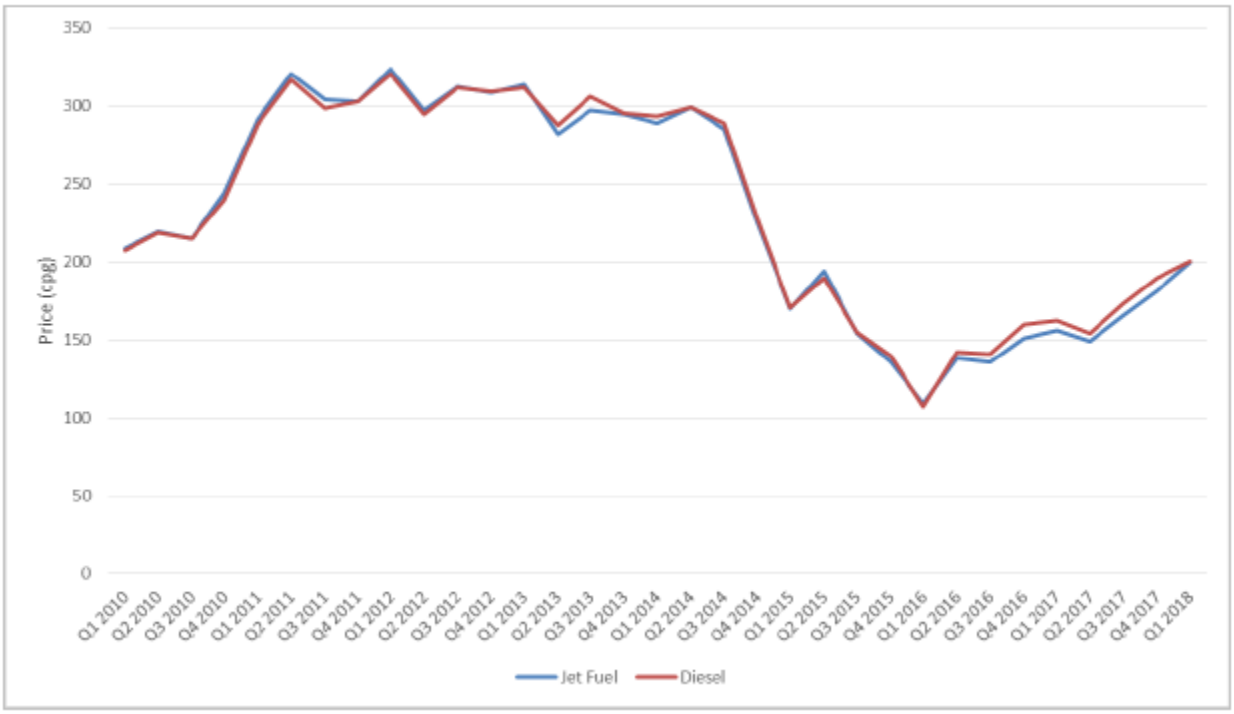


Figure 2. Jet Fuel and Ultra-Low Sulfur Diesel Prices in Los Angeles, 2010—2018



2. Due to the more stringent cold flow specification for jet fuel, alternative jet fuel requires more intensive processing than does on-road renewable diesel. Petroleum jet is relatively less burdened in meeting the jet specifications due to the inherent differences between fossil crude feedstocks and renewable jet feedstocks.

Due to the more stringent cold flow specifications for jet fuel, alternative jet fuel requires more intensive processing than does on-road renewable diesel. The AltAir Facility in Paramount, California is the only U.S. facility that is steadily producing and supplying commercial quantities of alternative jet fuel. AltAir supplies to the common hydrant fueling system of Los Angeles International Airport pursuant to a contract with United Airlines. AltAir purposefully designed its production process to produce renewable jet. The company estimates that it costs approximately $0.16/gallon more to make renewable jet than it would cost for a comparable renewable unit configured to only make renewable diesel. Petroleum jet is less burdened in meeting the jet specification due to the inherent differences between the composition of fossil crude feedstocks (which contain molecules in the jet and diesel boiling range) as compared to renewable jet feedstocks (which rely on cracking of a diesel boiling range molecule to form a jet molecule). Although crude oil does not necessarily need to be cracked to form a jet, it does still need to be fractionated from the diesel, which costs about $0.09/gallon. The normal crack spread does not cover this differential, so there is a preference to make diesel instead of jet in most refineries.

3. Jet fuel is not burdened at the rack by the cost of cap and trade allowances as is petroleum diesel. In today's market, this provides renewable diesel with an effective .15/gallon price discount to petroleum diesel that alternative jet fuel will not receive.

The various market factors are best illustrated with reference to real world pricing in today's California market. The Oil Price Information Service ("OPIS") provides daily information on petroleum prices world-wide. OPIS is widely recognized in the petroleum industry as the most reliable and accurate source for spot benchmark pricing.[15] OPIS publishes a daily report on U.S. west coast rack pricing of various petroleum products at various locations in the western U.S. This report is entitled the OPIS West Coast Spot Market Report ("OPIS Market Report"). The AJF Producers appreciate that OPIS provided a limited copyright waiver approval authorizing the submission of the March 29, 2018 OPIS Market Report to be included as Exhibit A to this comment, and to be made part of the rulemaking record.

[15] For further information on the Oil Price Information Service and its spot pricing services, see https://www.opisnet.com/about/company-overview/

On page 5 of the OPIS Market Report, OPIS posts pricing for California Cap-at-the-Rack prices. Pursuant to California's Cap-and-Trade program, petroleum diesel fuel triggers allowance obligations for the terminal position holder that sells diesel over the rack. OPIS tracks the current market value of the allowance as expressed on a cents per gallon basis. The following chart illustrates the cost of allowances reported on March 29, 2018:

Prompt Calif. Cap-at-the-Rack Prices (cts/gal)

Product	Price	Wk Avg	30-Day Avg
Summer CARB RFG-R	11.83	11.848	11.881
Summer CARB RFG-M	11.80	11.818	11.852
Summer CARB RFG-P	11.79	11.808	11.842
Winter CARB RFG-R	11.80	11.818	11.858
Winter CARB RFG-M	11.80	11.818	11.858
Winter CARB RFG-P	11.82	11.834	11.871
CARB No.2	15.03	15.052	15.099
B5 Biodiesel	14.28	14.302	14.347
Propane	8.25	8.262	8.288
LNG (cts/DGE)	10.75	10.762	10.796

The posting that is of primary importance to AJF producers from a market perspective is the CARB No.2 posting which refers to CARB Diesel. OPIS reports that the 30-day average for allowance costs attributable to a gallon of CARB Diesel was just over fifteen cents per gallon ($0.15/gallon). In contrast to petroleum diesel suppliers, renewable diesel suppliers are not obligated to purchase and retire allowances for renewable diesel that is sold over the rack or by other methods in the California market.

Conventional jet fuel sold in California also does not trigger carbon allowance obligations.

The result of this cap-and-trade obligation is to provide a relative discount of renewable diesel sold into the California market, as compared to petroleum diesel. Using the March 2018 example, if the bulk fuel pricing for petroleum diesel fuel and renewable diesel fuel was equivalent at $3.00 per gallon, a purchaser of petroleum diesel would pay an additional $0.15 to cover the allowance cost resulting in a net price of $3.15, whereas a renewable diesel purchaser would pay only the $3.00 price. If conventional jet fuel was also priced that day at $3.00 per gallon, the jet fuel purchaser would pay a net price of $3.00. Thus a biorefinery capable of producing both renewable diesel and alternative jet fuel could expect to receive a $0.15 per gallon premium for RD sales but no such premium for AJF sales.

4. Conventional jet fuel pricing is also not burdened with the LCFS compliance cost that is assessed at the rack for conventional diesel fuel resulting in an effective .07/gallon price discount to petroleum diesel in today's market that alternative jet fuel will not receive.

The second posting that is of importance to AJF producers from a market perspective is the OPIS California Low Carbon Fuel Standard posting. Like the Cap-at-the-rack pricing, OPIS reports the compliance costs attributable to a gallon of CARB Diesel. The following posting is from the March 29th OPIS Market Report.

OPIS California Low Carbon Fuel Standard

Product	Low	High	Mean	Change
Carbon Credit ($/MT)	140.000	145.000	142.5000	1.0000
CI Pts Ethanol ($/CI)	0.01141	0.01182	0.011615	0.000080
CI Pts Biodiesel ($/CI)	0.01766	0.01829	0.017975	0.000125
Carbon CPG Diesel (cts/gal)	6.72	6.96	6.840	0.050
Carbon CPG Dsl 95% (cts/gal)	6.38	6.61	6.495	0.045
Carbon CPG Gasoline (cts/gal)	10.43	10.80	10.615	0.075
Carbon CPG Gas 90% (cts/gal)	9.38	9.72	9.550	0.070

As listed in the report, the mean underlying LCFS price was $142.50 per metric ton during the applicable time period. This resulted in a mean compliance cost per gallon of diesel fuel of $0.068/gallon or almost seven cents per gallon. As is the case in the cap-and-trade program, renewable diesel suppliers do not accrue LCFS credit obligations. Similarly, conventional jet fuel sold in California also does not trigger LCFS obligations.

The result of this LCFS obligation is to provide a supplemental discount to renewable diesel sold into the California market, as compared to petroleum diesel. Using the same March 2018 example, if the bulk fuel pricing for petroleum diesel fuel and renewable diesel fuel was equivalent at $3.00 per gallon, a purchaser of petroleum diesel would pay an additional $0.07 to cover the LCFS compliance cost plus the cap-and-trade cost

of $0.15 resulting in a net price of $3.22, whereas a renewable diesel purchaser would pay only the $3.00 price. If conventional jet fuel was also priced that day at $3.00 per gallon, the jet fuel purchaser would pay a net price of $3.00. Thus a biorefinery capable of producing both renewable diesel and alternative jet fuel could expect to receive a $0.22 per gallon premium for RD sales but no such premium for AJF sales.

5. Under the federal Renewable Fuel Standard (RFS), AJF receives relatively fewer RINs than on-road diesel with renewable diesel generating 1.7 RINs per gallon and renewable jet fuel generating 1.6 RINs per gallon. This results in a 6% discount on RIN generation representing .06/gallon less incentive per gallon in today's market.

The Renewable Fuel Standard ("RFS) is a federal program that provides market based incentives to qualifying producers of renewable fuel by requiring petroleum refiners and importers to obtain renewable identification numbers ("RINs") based on their petroleum fuel volumes. There are multiple RIN categories in the RFS, with both renewable diesel and jet fuel typically generating D4 RINs, known as biomass-based diesel RINs. The key disadvantage that alternative jet fuel encounters under the RFS relates to the number of RINs generated compared to renewable diesel fuel generated on a per gallon basis. RD generates 1.7 RINs per gallon under the RFS, whereas renewable jet has been determined to generate 1.6 RINs per gallon.[16]

[16] 40 CFR §80.1415(b)(4) provides, "Non-ester renewable diesel with a lower heating value of at least 123,500 Btu/gal shall have an equivalence value of 1.7." Regarding renewable jet RIN generation crediting of 1.6, see EPA Compliance Help 2018, "RIN Generation and Renewable Fuel Volume by Fuel Type," at https://www.epa.gov/fuels-registration-reporting-and-compliancehelp/2018-renewable-fuel-standard-data

The OPIS Market Report also provides current market pricing for RINs. The RIN values are provided on an ethanol equivalent basis. The following table is applicable to RINs:

OPIS U.S. RIN Values (cts/RIN)

Product	Year	Low	High	Mean	Change
Corn Ethanol	2017	41.50	44.50	43.000	1.500
Corn Ethanol	2018	43.00	46.00	44.500	0.500
Biodiesel	2017	56.50	60.50	58.500	-1.500
Biodiesel	2018	64.00	68.00	66.000	-1.750
Cellulosic	2017	255.00	261.00	258.000	0.000
Cellulosic	2018	247.00	253.00	250.000	0.000
Adv. Biofuel	2017	55.50	59.50	57.500	-1.500
Adv. Biofuel	2018	63.00	67.00	65.000	-1.750

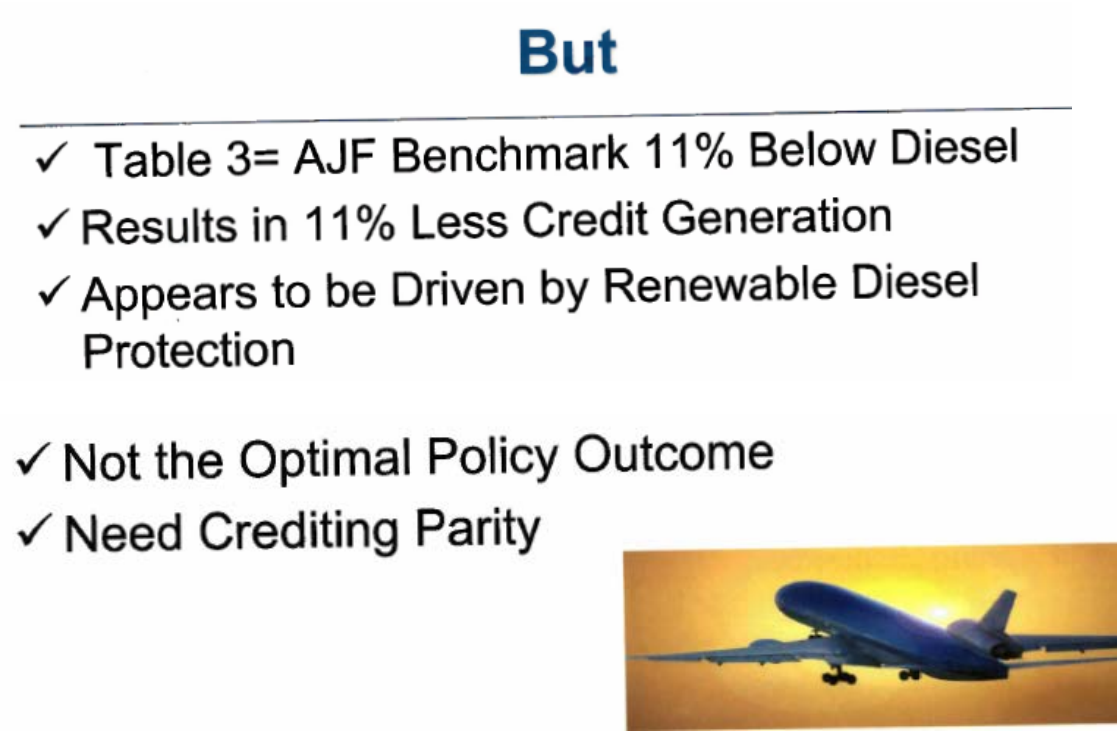
The applicable RIN value is listed here as "Biodiesel" with a 2016 mean price of $0.66 per D4 RIN. Adjusting the RIN value for the energy density of renewable diesel results in a RIN value per renewable diesel gallon of $1.056. The RIN generation discount per gallon between 1.6 RINs for AJF as compared with 1.7 RINs for RD results in approximately a 6% discount. Thus a RD producer would receive more than six cents per gallon ($.06) than an AJF producer would.

The result of this RFS discount is to provide an additional policy incentive to renewable diesel sold into the market, that is supplemental to the favorable California policy incentives. Using the same March 2018 example, the cap-and-trade cost of $0.15 plus the LCFS compliance cost results in a net price of $3.22, whereas a renewable diesel purchaser would pay only the $3.00 price. If conventional jet fuel was also priced that day at $3.00 per gallon, the jet fuel purchaser would pay a net price of $3.00. Thus a biorefinery capable of producing both renewable diesel and alternative jet fuel could expect to receive a $0.22 per gallon premium for RD sales but no such premium for AJF sales. In addition, the RD gallon would generate an additional $.06 in RIN value resulting in a net policy premium for RD of $0.28 as compared to AJF.

…

As examined in some detail by this comment and supported by market data, the production of renewable diesel is inherently favored over alternative jet fuel. While we have not attempted to assign a precise figure to it, conventional jet fuel typically sells at a discount to diesel fuel in the California market and this is predicted by the U.S. Energy Information Administration to continue in the future. According to the one existing commercial producer, alternative jet fuel production results in an additional cost per gallon of about $0.07 per gallon. The combined California and federal policy factors result in $0.28 of policy premium that favors RD production. These factors are cumulative and thus the existing policy and market landscape is heavily slanted to favor RD production over AJF production. (AJFP1_102-12)

Comment:



Policy Options (Opt-in Fuel)

- Use Table 2- Diesel Curve
  - Crediting Parity for fuels produced with same feedstocks and at same facilities
- Use Fixed Benchmark Not Curve
  - No CI Regulation of Jet Fuel
  - All GHG Reduction is Additional
- Use Hybrid= Fixed Benchmark then Curve
  - No More Credits than RD
  - Preemption
  - Phase In Period

What's the Policy Problem?
On-Road Fuel Always Wins.

Prompt Calif. Cap-at-the-Rack Prices (cts/gal)

Product	Price	Wk Avg	30-Day Avg
Summer CARB RFG-R	11.83	11.848	11.881
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Adv. Biofuel	2017	55.50	59.50	57.500	-1.500
Adv. Biofuel	2018	63.00	67.00	65.000	-1.750

RD Policy Bonuses ($/gallon)

Cap at the Rack	.15
LCFS Cost	.07
RIN Value	.06
TOTAL	.28

(AJFP2_B1-1)

Comment: There's always the "but" slide, and the but is the one remaining issue that I want to speak to today, not to take away anything in terms of our support for the overall proposal, but we do have an issue on both the technical and the policy side in terms of the carbon intensity level that has been proposed as the benchmark for aviation fuel. And that references specifically table 3 in the regulation. It is our perspective based on the ISOR that this may have been driven out of excess of concern to protect the on-road renewable diesel supply. But it is our position that it was not the correct technical determination nor the best policy outcome.

So we would urge the Board to direct staff to reconsider this and move toward crediting parity.

Essentially we have about an 11 percent carbon intensity delta between renewable diesel and conventional jet fuel, and that results in an 11 percent less opportunity out there for credit generation in the jet space.

This is my one technical slide. I'm not going to speak to this extensively other than to show that relative to refinery efficiency, the assumptions that were made on the jet-fuel side were negative from a carbon intensity perspective.

From a policy option perspective, there were a wide range of approaches that would have drawn the curve much closer or made it identical to renewable diesel fuel. These are detailed in our letter. All of them would have moved us toward crediting parity either immediately or over a 5- or 10-year period, and we think these would have been a preferable policy outcome.

The policy problem is there's essentially a tilted playing field right now. From a policy standpoint, we have the two California programs plus the federal program, not deliberately slanted against jet fuel, but each one of those programs creates a policy disparity. Together there's about 28 cents less incentive to go into the jet fuel market. With this crediting disparity, it would put it over 40 cents from a policy standpoint.

…

Certainly. So the charts that are here - and all of these charts are in the letter as well - are essentially OPIS postings, the rack pricing that is out there for the California market. These are from I believe March 28 of this year. OPIS actually posts the costs that are assigned to the Cap-at-the-Rack program. So the costs essentially that conventional diesel fuel needs to pay on an allowance basis per gallon. That's that first chart that you see, with "CARB number 2" highlighted, and the 30-day average of 15 cents. So that's 15 cents that diesel fuel over the rack needs to pay.

Conventional fuel is not burdened with that rack price, so it doesn't have that 15 cent cost associated with it. So I'd call that an inadvertent policy discrepancy.

But if you're an alternative jet fuel producer, if you look at your sales opportunity, on the on-road market you've got another 15 cent worth of price opportunity out there that you don't have if you go into the alternative jet fuel market.

The parallel program -- or the parallel chart on the Low Carbon Fuel Standard is the next one, where it's highlighted "carbon cost per gallon diesel fuel, 6.84 cents." That's the LCFS cost that OPIS assigns on that -- on that particular day to cover the cost of allowances.

Again, because the diesel fuel is an obligated fuel, they would need to pay that cost in the conventional on-road market; whereas in the conventional jet fuel market, they wouldn't be burdened with that cost.

So both of these are policy outcomes that basically provide additional opportunity for revenue if you sell into that on-road market that don't exist in the jet fuel market.

The third policy disparity is in RIN generation, the Federal Renewable Fuel Standard. And there, that has caused -- the additional 6 cents is caused by a different equivalence value of jet fuel as compared to diesel fuel. You generate less RINs. So in today's market you get about 6 cents less per gallon.

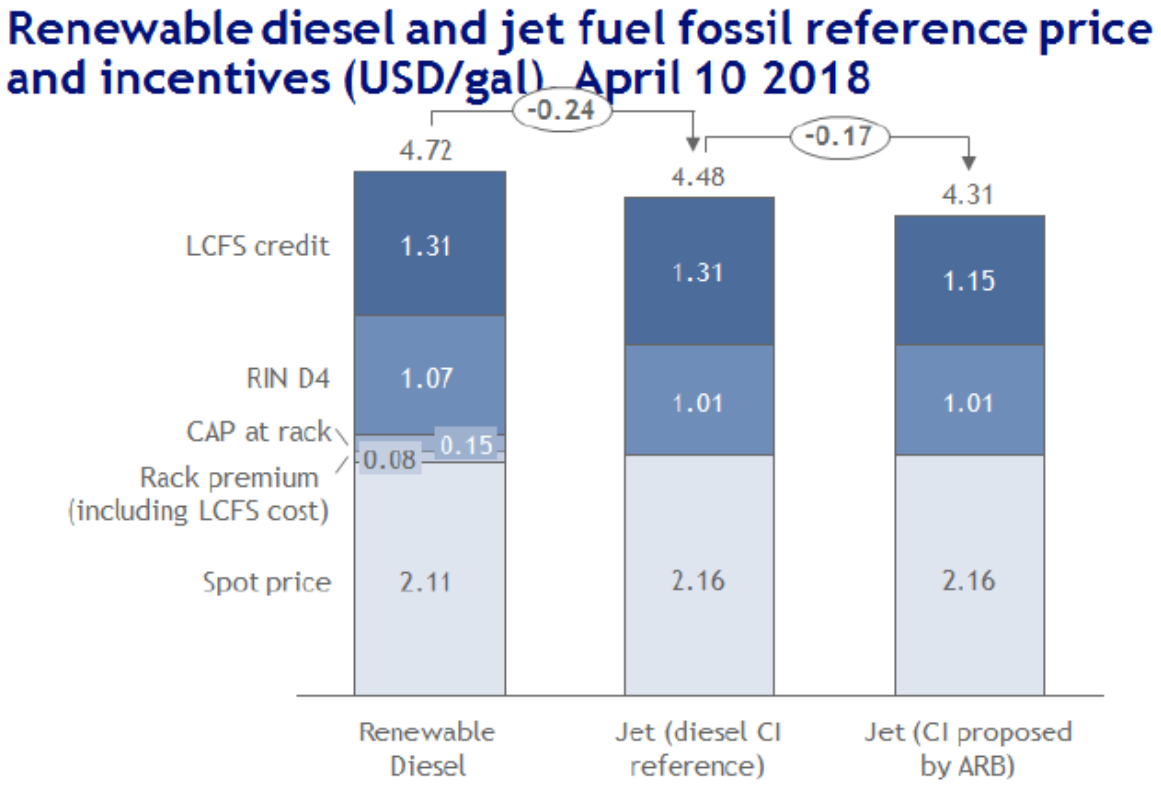
So those are -- all of these have -- I think the way I would summarize it is, because all of these programs have focused on the on-road market, and jet fuel has traditionally been

exempted, they end up creating incentives to supply in the on-road market. And within our producer group - and we'll have both Neste and AltAir also giving comments today - they see -- when they are making a market decision, they see additional revenue opportunities for an on-road fuel that they don't get for an aviation fuel. (AJFP3_T6-3)

Comment: Secondly, CARB should reconsider the shape of the proposed carbon intensity curve as the benchmark for conventional jet fuel from a policy perspective. The LCFS and its proposed amendments have no regulatory mandate to reduce the carbon intensity of jet fuel over time unlike the requirements for diesel and gasoline to reduce their respective carbon intensities 7% and 8% by 2020 and 20% for both fuels by 2030. Removing the decreasing carbon intensity benchmarks for jet fuel would be consistent with the fuel's existing exemption and would appropriately recognize the difference between CARB's regulatory authority over diesel and gasoline and its limited authority to offer incentives to reduce aviation emissions.

It is our impression that staff is acting in an abundance of caution to draw the AJF compliance curve in a highly conservative manner to discount credit-generation opportunities for AJF to avoid incentives to divert AJF from on-road renewable diesel supply to California. Neste, a producer of both renewable diesel and renewable jet, does not intend to cannibalize its renewable diesel business for renewable jet fuel. Rather, the expectation is to expand renewable fuel production capacity. Indeed, Neste is currently studying the feasibility of a new 300+ million gallon per annum expansion of one of its existing refineries and preparing for a final investment decision later this year.

A review of existing market and policy factors clearly demonstrates that decreasing the carbon intensity benchmark for jet fuel is not needed to prevent market distortions given the many factors (including including production economics, fuel specifications, market forces, other California climate policies, and the federal Renewable Fuel Standard) that will still place AJF at a market disadvantage, and the fact that AJF production also necessarily results in the production of other fuels within a product slate. The charts below summarize current price and market data.



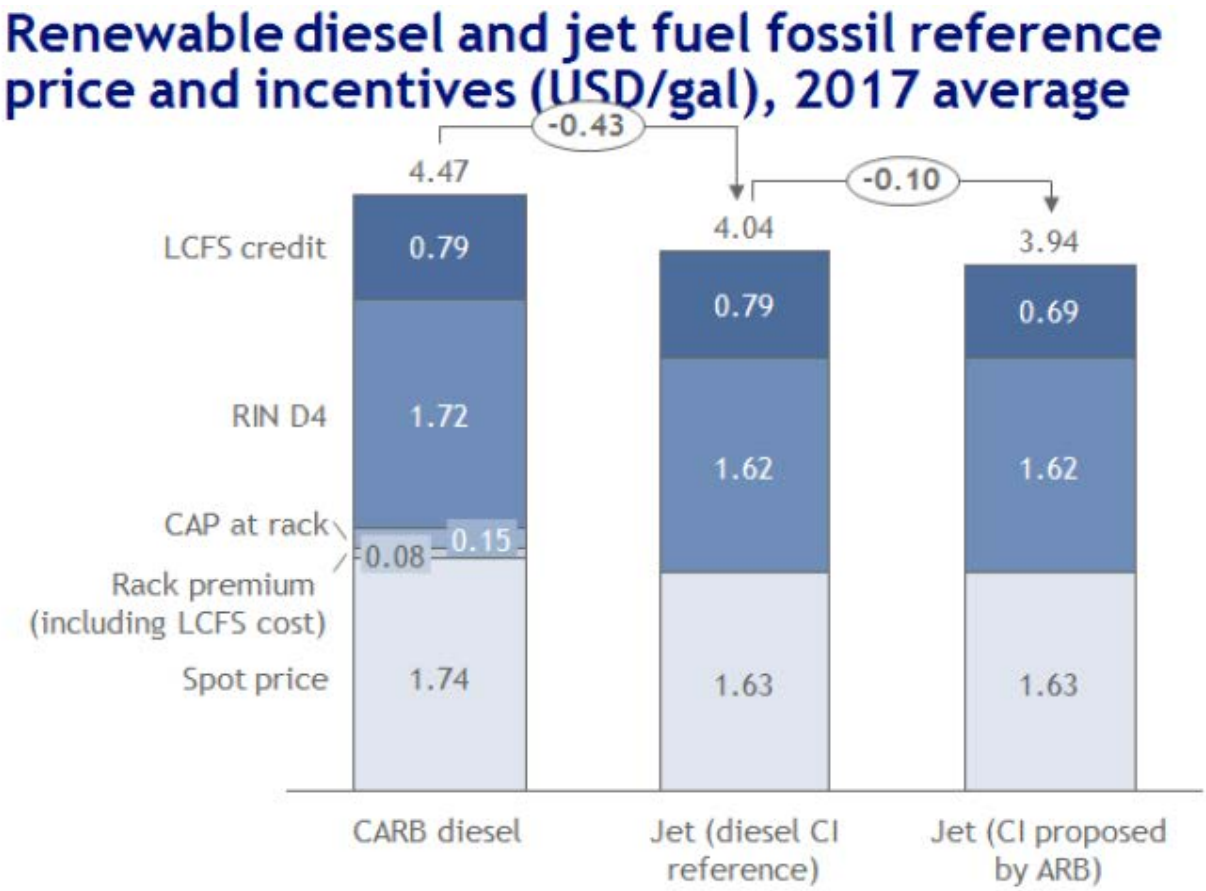
Source: Neste analysis based on OPIS and PLATTS data.

Data (10 April 2018): D4 RIN at USD 0.63/gal; 1.7 RINs/gal for renewable diesel, 1.6 RINs/gal for renewable jet fuel. LCFS at USD 148/credit and CPG for diesel was 0.07 cts/gal; renewable diesel / jet fuel from animal fat with CI of 35 gCO2/MJ (RNWD005); reference CI of 102.01 (diesel) and 89.75 (jet fuel)

Note: difference in diesel and jet spot price includes cost of RIN compliance. Rack premium includes cost of LCFS compliance.

Assuming the proposed conventional jet CI baseline (89.75), renewable diesel would currently have a 40 cents/gal higher incentive than renewable jet fuel.

Similar trends hold for historical data as well. The following chart shows 2017 average price comparison.



Source: Neste analysis based on OPIS data.

Data: D4 RIN: 2017 average price was USD 1.01/gal; 1.7 RINs/gal for renewable diesel, 1.6 RINs/gal for renewable jet fuel. LCFS: 2017 average was USD 89/credit and average CPG for diesel was 0.04 cts/gal; renewable diesel / jet fuel from animal fat with CI of 35 gCO2/MJ (RNWD005); reference CI of 102.01 (diesel) and 89.75 (jet fuel)

Note: difference in diesel and jet spot price includes cost of RIN compliance. Rack premium includes cost of LCFS compliance.

In 2017 renewable diesel would have had a 40 cent/gal higher incentive than renewable jet fuel, even if same fossil reference CI value is used. The proposed, lower CI baseline would have further discounted the AJF relative to the on-road renewable diesel by an additional 10 cents/gal.

Taken as a whole, these factors demonstrate that AJF production will remain significantly disadvantaged from a producer vantage point compared to on-road fuel even after AJF becomes eligible to generate LCFS credits. ARB should closely examine this economic framework and recognize that it provides ample protection to California's renewable diesel supply; and therefore establish LCFS crediting parity for AJF production.

Neste proposes a benchmarking approach that would be more consistent with ARB's regulatory authority to establish a fixed baseline standard for conventional jet fuel - rather than a declining standard. This would remain consistent with the fuel's existing exemption and opt-in status and would appropriately provide a voluntary incentive, but not mandatory regulatory standard, for the aviation sector. The baseline would be fixed at the 2010 conventional jet fuel baseline (94.04 gCO2e/MJ considering updated refinery efficiencies). As noted above, staff's proposed approach is likely motivated by a desire to create a level playing field with ground transportation fuels. The benchmarking proposals suggested above would maintain a level playing field as they would not result in greater LCFS incentives for AJF than diesel substitutes.

Further in order to avoid an LCFS crediting mechanism that disproportionately incentives low-carbon aviation fuel over low-carbon on-road fuel, the **AJF baseline could further decline in tandem with the diesel standard when the diesel standard crosses and is equal to or lower than the 2010 conventional jet fuel baseline.** This would provide early year incentives to continue to send strong support and incentive signals to producers of renewable diesel and renewable jet fuel, would recognize the inherent and existing economic discrepancies between jet and on-road diesel, and would avoid inappropriate and unintended incentives away from on-road diesel in later years when the diesel baseline declines below the 2010 conventional jet baseline. (NESTE1_76-6)

Comment: The inherent deficit that already exists in terms of costs is already built into it. When you couple that with again inaccuracies in the benchmarking and having a lower benchmark, and also then having a starting point for an obligated fuel that already starts behind a curve and has further reductions when you're dealing with a program that's already on a declining basis, so coming into the program already at, you know, 5-plus percent reductions; all those deficiencies make it difficult for parity and are unlikely to really provide the kind of incentive or accuracy that you'd like to have an expanded low-carbon fuel concept that also includes alternative jet fuels. (NESTE2_T11-5)

Comment: We recognize that there is a concern that the addition of a voluntary LCFS program for Alternative Jet Fuel has the potential to cannibalize or reduce the Renewable Diesel fuel that is currently produced by the LCFS Program. However, we believe that the opposite will occur. Even with the addition of LCFS credits for jet fuel, the economic incentive to manufacture Renewable Diesel will be greater than jet fuel. However, since both are manufactured in the same process, the likelihood of increasing the overall manufacturing capability of both products is increased, which means that this Alternative Jet Fuel measure will also incentivize additional Renewable Diesel production, resulting in increased production in sales for both fuels. (ALTAIR1_B13-1b)

Comment: The first is to address the concerns that's been expressed that enabling renewable jet to generate credits will cause producers to reduce renewal diesel production in favor of renewable jet. And I'd like to counter that, because empirically we don't believe that that's going to happen. Even if the renewable jet credit generation were to equal the renewable diesel generation, the margin for renewable diesel still

exceeds renewable jet from a commercial perspective. We're not incentivized to cannibalize the renewable diesel with renewable jet.

And that's primarily driven by two aspects: One, the cost of production of renewable jet still remains higher; there's more processing required. And then, secondly, the monetary value of both the physical product as well as the credits associated with renewable diesel exceed the -- those available for renewable diesel.

However, it's important to point out that supporting renewable jet in fact supports renewable diesel. So if you think about, you know, just like petroleum crude, a renewable crude oil contains a mixture of different molecules of various sizes. But the majority of those in the feedstocks that we primarily used for our production are a diesel-range molecule with the minority being jet. So our production on a yield basis is going to produce significantly more road diesel. And what that means is incremental addition of capacity -- or new capacity for renewable jet actually means incrementally more renewable diesel. So differently, one unit of jet can equal approximately or up to eight new units of road diesel. So again, supporting the jet actually supports substantially more production of renewable diesel. (ALTAIR2_T40-1)

Comment: We support the suggested approach of either utilizing the current diesel curve as defined in Table 2 or using a hybrid approach with a fixed benchmark through 2022, then using the benchmark CI for diesel for the corresponding year from 2023 on. We believe these approaches would not negatively affect renewable diesel production due to the economic constraints on the ATJ market. (LANZATECH1_77-9a)

Comment: Second, we suggest removing the decreasing CI benchmark for jet fuel (initially 84.23 g CO_2e/MJ in 2019) and maintaining a flat CI benchmark instead. We note that the LCFS is not intended to set jet fuel CI standards and thus should not be proactively reducing the CI benchmark for AJF. However, we do agree that the AJF baseline should begin to decrease along with road diesel when CI benchmark parity is achieved. This would avoid incentivizing AJF more than renewable diesel and thus distorting the LCFS program.

We recognize that there are concerns about market distortions in favor of AJF with our proposed changes. However, we would like to point out that even with these changes, AJF will remain economically disadvantaged vs. other alternative fuels.

The production of AJF is currently disincentivized in California because it is not eligible for LCFS credits. Providing these credits, which we feel are warranted from economic, technical and regulatory perspectives, would foster the airline industry’s role in helping to obtain the necessary financing for AJF facilities through dedicated offtake agreements. In addition, research by the National Renewable Energy Laboratory indicates that incentivizing AJF would likely result in a significant increase in production for renewable diesel as well. (UNITED1_B12-3)

Comment: The second is to either maintain a static carbon intensity baseline for jet fuel or, at a minimum, adopt an approach that would adjust the jet fuel carbon intensity

baseline downward only at the point at which the diesel carbon intensity benchmarks reach the jet fuel carbon intensity starting baseline.

Without these adjustments the carbon intensity provisions currently proposed would again piece AJF at -- place AJF at a disadvantage relative to other renewable transportation fuels.

Under these adjustments we propose every gallon of AJF would still bring significant emission benefits compared to conventional jet fuel. (UAA4A1_T36-3)

Comment: The current market for AJF is only around 20 million gallons produced globally, and may not be able to respond to demand as quickly as ARB anticipates. AJF producers need to maximize credit generation potential to make this an effective market. SFO encourages ARB staff in finalizing the technical details of the LCFS amendments to work with the airlines, AJF producers, and their industry associations to develop a value for the LCFS credits that will result in meaningful adoption and scale-up of these important low-carbon fuels. (SFO1_B18-2)

Comment: The current global market for AJF is only around 20 million gallons annually and needs significantly to be -- needs significant and well-designed policy stimulus and incentive to scale up these important low-carbon fuels.

For perspective, just 1 percent of AJF blend at SFO would require about 10 million gallons of fuel annually.

For this reason SFO encourages the Board to direct ARB staff to examine the submissions of the airlines and AJF producers in this rulemaking when finalizing the carbon intensity benchmark for conventional jet fuel that will result in a meaningful AJF credit to -- excuse me -- credit value to accelerate California's leadership in this anticipatedly increasing competitive global market for AJF. (SFO2_T17-2)

> **Agency Response:** Staff modified the original proposal in response to these comments. Attachment A to the Notice of Public Availability of Modified Text posted June 20, 2018 reflects the modified benchmarks, which remain fixed at the 2010 baseline CI for conventional jet fuel until the benchmark for diesel substitutes declines below the CI baseline for jet fuel in 2023. Beginning in 2023 and each year thereafter, the annual CI benchmark for conventional jet substitutes is equivalent to the annual CI benchmark for diesel substitutes. Staff believes that the revised benchmarks will provide more incentive for production of AJF while continuing to avoid the potential situation where AJF gains a market advantage over renewable diesel thereby leading to a shift from renewable diesel production to AJF production.

D-1.5. Multiple Comments: *Cost-Effectiveness of Alternative Jet Fuel*

Comment: As A4A has noted previously, allowing AJF producers to generate LCFS credits would significantly improve the economics of new and existing facilities by allowing them to generate credits from all transportation fuels produced. The AltAir

facility, as well as other potential AJF facilities, necessarily produces both renewable diesel and AJF, along with other products. Given that the LCFS is intended to spur investment in the entire renewable fuels industry, we encourage CARB to strengthen this investment signal by allowing LCFS credit for all low carbon transportation fuels.

Incentivizing the production of AJF is particularly appropriate in light of the critical role the airline industry can play in helping to obtain financing for facilities through dedicated off-take agreements, a role that the airline industry is uniquely situated to fill. Modeling conducted for A4A by the National Renewable Energy Laboratory (NREL) pursuant to NREL's Biomass Scenario Model demonstrates the synergistic relationship that airline off-take agreements can have when coupled with access to credit markets like the LCFS. Notably, NREL's modeling indicates that an additional credit for AJF would likely result in significantly increased production of both AJF and renewable diesel.[2]

[2] *See* National Renewable Energy Laboratory, "Effect of Additional Incentives for Aviation Biofuels: Results from the Biomass Scenario Model," presented at CARB's March 17, 2017, public working meeting (NREL presentation) (attached hereto).

CARB's proposal to add AJF as a credit-generating fuel would also lower compliance costs for regulated parties and is consistent with ARB Resolution 11-39, which seeks to explore the "expansion of the LCFS credit trading market" and "incorporation of a flexible compliance mechanism…."[3] Including AJF in the LCFS credit trading market enlarges the pool of credits available to obligated parties further promoting cost containment. In addition, crediting AJF would assist in lower compliance costs by providing an additional avenue for low carbon fuel use that is unaffected by the blending constraints imposed on ground transportation fuels.

[3] *See* Resolution 11-39, Amendments to the Low Carbon Fuel Standard Regulation at 9 (Dec. 16, 2011).

(A4A1_57-2)

Comment: Allowing AJF producers to generate LCFS credits would be a strong positive step in making AJF a cost effective option for air sector carbon reductions. Given that the LCFS is intended to spur investment in the entire renewable fuels industry, we strongly support CARB's proposal to strengthen this investment signal by allowing LCFS credit for all low carbon transportation fuels.

The proposal would also lower compliance costs for regulated parties and is consistent with ARB Resolution 11-39, which seeks to explore the "expansion of the LCFS credit trading market" and "incorporation of a flexible compliance mechanism…." Including AJF in the LCFS credit trading market enlarges the pool of credits available to obligated parties further promoting cost containment. In addition, crediting AJF would assist in lower compliance costs by providing an additional avenue for low carbon fuel use that is unaffected by the blending constraints imposed on ground transportation fuels. (NESTE1_76-3a)

> **Agency Response:** Staff acknowledges the support of the proposed amendment to include AJF as an opt-in fuel and appreciate the contribution of the modeling conducted for A4A by NREL that demonstrates the synergistic relationship that airline off-take agreements can have when coupled with access

to credit markets. Staff agrees that this proposal could incentivize the production of AJF.

Staff also agrees that allow AJF producers to generate LCFS credits would be a strong positive step in making AJF a cost effective option for air sector carbon reductions.

D-1.6. Multiple Comments: *Environmental Benefits of Alternative Jet Fuel*

Comment: California Airports are already well versed in the language and use cases for alternative fuels, as consumers of renewable diesel and CNG to reduce the impacts of our ground fleet, including our ground support equipment and airport access vehicles, and are eager to support our Airlines and ARB in pushing these gains into our skies. Due to this existing demand, we have adjacency with facilities that are currently supplying our Airports' with alternative ground transportation fuels, who have also expressed interest in an incentive that could expand their production to also supply AJF. We've pushed for these alternative fuels because we care about the health of our workers and the air quality of our region, noting that many of our Airports exist within "non-attainment" areas for PM 2.5 and ozone. As you are aware, SAF represents an ultra-low sulfur fuel that can help power jet engines that reduce particulate emissions in their exhaust as much as 50-70 percent, confirmed by a recent NASA study and also as cited by ARB in the Staff Report: Initial Statement of Reasons (at p. V-18). SAF also maximizes the benefits, and the LCFS would reduce the related costs, of greenhouse gas reduction as many of our Airports look towards Airport Carbon Accreditation, thereby allowing our Airports to more fully contribute to the State's AB32 Targets and our Airlines' own carbon neutral growth targets established through the International Civil Aviation Organization (ICAO). (CAC1_49-2)

Comment: Finally, AJF will help California airports and the State progress towards mutual and ambitious carbon reduction and public health goals. We're eager to support our airlines and ARB in pushing gains we have made with renewable fuels in ground-based transportation into our skies. We've pushed for these alternative fuels because we care about the health of our workers and the air quality of our regions.

And we are eager to continue to partner with ARB staff to track our AJF success and to share that on the global stage at our upcoming global climate action summit and beyond. (SFO2_T17-4)

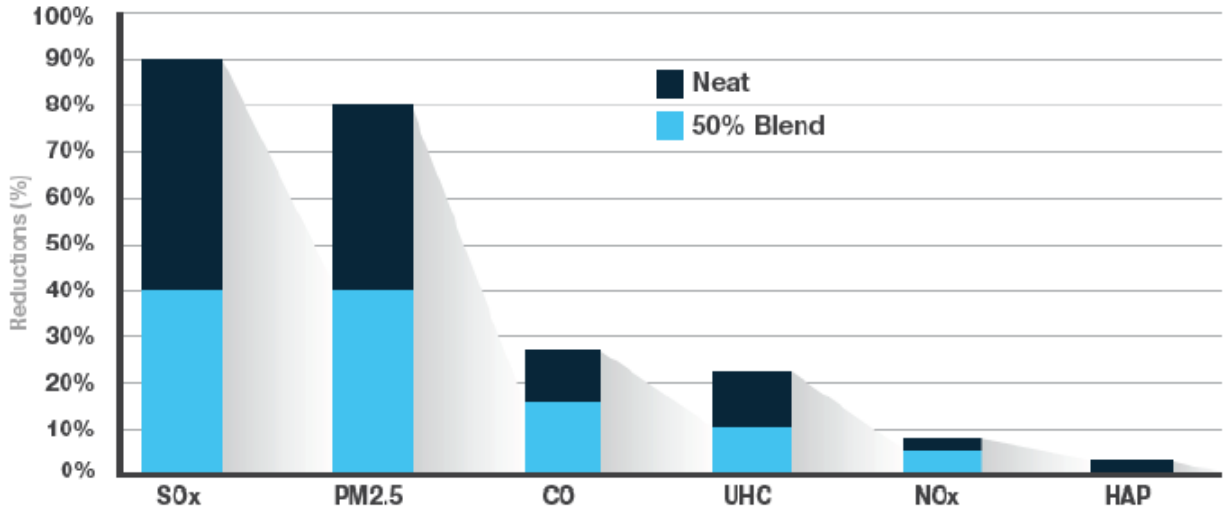
Comment: Crediting AJF on an opt-in basis in the LCFS also advances California's environmental goals. Promoting the use of AJF will not only support the State's GHG reduction targets, it would also provide substantial co-benefits through reductions in conventional air pollutant emissions. While CARB already reports in its Initial Statement of Reasons (ISOR) that AJF can provide both nitrogen oxide (NOx) and particulate matter (PM) reductions,[4] a comprehensive assessment under the Transportation Research Board's Airport Cooperative Research Program (ACRP) confirms that the use of AJF can reduce emissions of sulfur oxides (SOx), PM, carbon monoxide, unburned hydrocarbon emissions, and NOx to varying degrees, with reductions in SOx and PM

being particularly dramatic.[5] The results of this assessment are illustrated in Figure 1 below. Thus, AJF could be used to strategically target airports like Los Angeles International Airport that are located in air basins facing significant air quality challenges, which gives AJF an advantage as an air quality improvement measure over its on-road counterparts which are more widely distributed statewide.

[4] CARB, Staff Report: Initial Statement of Reasons at V-18-20 (Mar. 6, 2018) (CARB ISOR).

[5] *See* Transportation Research Board, *ACRP Project 02-80: State of Industry Report on Air Quality Emissions from Sustainable Alternative Jet Fuels* at 5 (April 2018) (available at http://www.trb.org/Aviation1/Blurbs/177509.aspx).

Figure 1. The Airport Cooperative Research Program Project 02-80: Representative Air Pollution Emission Reduction from the Use of Sustainable Alternative Jet Fuel



(A4A1_57-3)

Comment: As noted in the staff proposal, existing data suggests that the use of AJF may reduce criteria pollutant emissions during taxi, takeoffs and landings. Increased use of AJF in the future could provide significant air quality and health benefits to local air sheds, including to disadvantaged communities located near airports. Such ancillary benefits are a powerful incentive for including AJF in the LCFS. We anticipate that the details and scope of the criteria pollutant reductions will be more accurately modeled, measured and quantified as the scale of AJF production and use in California is expanded." (NRDC1_81-13a)

Comment: As noted in the staff proposal, existing data suggests that the use of AJF may reduce criteria pollutant emissions during taxi, takeoffs and landings. Increased use of AJF in the future could provide significant air quality and health benefits to local air sheds, including to disadvantaged communities located near airports. Such ancillary benefits are a powerful incentive for including AJF in the LCFS. We anticipate that the details and scope of the criteria pollutant reductions will be more accurately modeled, measured and quantified as the scale of AJF production and use in California is expanded. (COALITION1_107-4a)

Comment: V. CARB's Environmental Analysis Confirms Environmental Benefit

A4A outlined the extensive GHG emissions benefits and local air quality emissions benefits in Section I of these comments. Further, we expressly support CARB's conclusion in the Draft Environmental Assessment, conducted pursuant to 17 CCR 6005, that "[w]ithout the use of AJFs, it could be difficult to achieve long-term GHG emission reduction goals . . ."[17] in the State, and that the "likely outcome of the Proposed Amendments' inclusion of AJF is . . . that the total air quality benefit increases."[18] As noted above, independent analysis by NREL and ACRP confirm the reduction in criteria pollutant emissions from use of AJF.

[17] *Id.* at 207.

[18] *Id.* at 67.

(A4A1_57-2a)

Comment: Moreover, as CARB points out in its ISOR, the reductions in emissions with local air quality impact that accompany the carbon emissions reductions incentivized by the LCFS also support the goal established by the California Environmental Justice Advisory Committee (EJAC) "for the State to provide and facilitate 'access to clean transportation technologies'" as means of advancing the State's environmental justice goals.[6] Airports are major hubs of economic activity, with emissions from that activity reaching nearby communities. Unfortunately, residences in close proximity to airports may be disproportionately disadvantaged, in terms of socioeconomic impact and/or environmental impacts. This assertion is particularly evident in California where Los Angeles International Airports is located in a CalEPA-designated disadvantaged community; San Jose and San Francisco International Airports are both located next to CalEPA-designated disadvantaged communities; San Diego International Airport is located next to CalEPA-designated low income community; and Sacramento International, Santa Monica Municipal, and John Wayne Airports are located next to CalEPA-designated disadvantaged and low-income communities.

[6] CARB ISOR at VII-5 (citing to AB 32 EJAC Recommendations for Proposed 2017 Scoping Plan Update).

While the reduction any emissions with local air quality impacts that result from the addition of AJF as a credit-generating fuel under the LCFS will help California meet its environmental justice goals, CARB highlights PM reductions from AJF as an important example:

> CARB staff has also heard concerns about particulate emissions from the residents of disadvantaged communities living near airports. Since airports and aviation fall under federal regulatory jurisdiction, incentivizing the use of cleaner jet fuels with fewer emissions than traditional jet fuels is one way California is helping residents near these facilities. The proposed amendments will permit alternative jet fuels to generate LCFS credits, thus incentivizing their use and yielding the accompanying PM reduction co-benefits. These emissions reductions are greatest during landings, take-offs, and the taxiing of the plane on the airstrip; providing direct PM emissions reductions to the residents of communities near airports.[7]

[7] CARB ISOR at VII-7 and VII-8.

Indeed, CARB's AJF proposal will bring synergistic local air quality benefits in the vicinity of airports, benefitting disadvantaged communities nearby. (A4A1_57-3a)

Comment: In addition to the CO2 reductions which will benefit the climate change goals of this program by adding this fuel as a voluntary measure for the airlines, the associated reduction in criteria co-pollutants that staff expects in Appendix F for PM (45%), SOx (40%) and NOx (12%) for the alternative jet fuel improvements it will achieve for the California air basin. (ALTAIR1_B13-1a)

Comment: The second point that I'd like to highlight in the realm of environmental justice has to do with improved emissions that happened as a result of the use of renewable aviation fuel. As pointed out in the staff report, there's a significant reduction of criteria pollutants with the use of renewable jet versus petroleum jet. In numbers, we have reductions of approximately 45 percent particulate matter, 40 percent SOx, and up to 12 percent NOx as a result of using these fuels. And very importantly, a majority of these emissions actually occur upon takeoff and landing of aircraft. And what that means is you actually will be able --

…

The last point there is that the substantial reductions actually happened near the airport, which often happen to be in the locations of disadvantaged communities. (ALTAIR2_T40-2)

> **Agency Response:** Staff acknowledges the support of the proposed amendment to include AJF as an opt-in fuel and appreciate the support of criteria pollutant emissions data presented in the ISOR.
>
> In regards to the comment submitted by NRDC1 and COALITION1, staff agrees that expansion in the use of AJF at commercial scale will bring improved opportunity to evaluate the full criteria pollutant benefits.
>
> Staff also appreciates the willingness in SFO2_T17-4 to track the success of AJF and share that on the global stage.

D-1.7. *Environmental Disbenefits*

Comment: We recommend that CARB thoroughly evaluate the equity and environmental justice impacts of including alternative jet fuel in the LCFS. We are concerned that since alternative jet fuels are fairly analogous to renewable diesel – they are both produced by the catalytic hydrogenation of non-fossil oils such as vegetable oil, used cooking oil or tallow – and so could lead to competition for feedstock and production capacity. This competition could affect progress towards reducing diesel pollution in California, which is a critical step towards addressing many of the critical air quality issues affecting disadvantaged communities. Similarly, the incorporation of alternative jet fuels under the LCFS will ultimately result in a net transfer of revenue from on-road fuels, as gasoline and diesel providers purchase credits for compliance, to aviation fuels, which will be one source of such credits. Given that the typical airline

passenger is of higher-income that the typical driver, this wealth transfer could lead to dis-equitable outcomes. We wish to be clear: we are not aware of any research into the equity impacts of these particular fuels in a context relevant to California and have seen no evidence that indicates that including alternative jet fuels under the LCFS will lead to dis-equitable outcomes. We anticipate that the equity-promoting impacts of cleaner air around airports and reducing the impacts of climate change are of greater magnitude than the concerns discussed above. Given California's strong progress in the promotion of justice and equity, it is worth taking a deliberate and objective look at these provisions before they become deeply entrenched within the program. (NEXTGEN1_124-45)

> **Agency Response:** Staff disagrees that using alternative jet fuel could lead to competition for feedstock and production capacity for renewable diesel. As indicated in the ISOR, the airline industry is developing a strong record for partnering with AJF producers through direct investment and off-take agreements. Additionally, as many stakeholders have indicated in comment letters, producers forecast less revenue from sales of alternative jet fuel than renewable diesel because jet fuel has historically sold at a discount to on-road diesel in the California market and future projections predict this trend will continue. Therefore, because AJF and renewable diesel are often produced in the same facility using the hydrotreating process, staff believes that inclusion of AJF is likely to lead to increased investment in such facilities, thereby increasing the production of both alternative fuels.
>
> Staff is also not "aware of any research into the equity impacts of these particular fuels in a context relevant to California and have seen no evidence that indicates that including alternative jet fuels under the LCFS will lead to dis-equitable outcomes." As mentioned in the ISOR and through stakeholder comments, increased use of AJF in the future could provide significant air quality and health benefits to local air sheds, including to disadvantaged communities located near airports.
>
> Finally, staff believes that it is very important that California show an interest in addressing a significant and growing source of GHG emissions. Currently, GHG emissions from aviation contribute to approximately two percent of the total global emissions and are expected to grow. Of all of California GHG emission policies, staff believes that the LCFS is best positioned to be the first State policy to address the growing emissions from the aviation sector.

D-1.8. Multiple Comments: *Point of Credit Generation*

Comment: We assume that, in the case of renewable jet fuel produced by co-processing renewable feedstocks in refineries, the point of credit generation will be the refinery gate. This renewable jet will not be segregated from petroleum jet as it leaves the refinery, making it impossible to track it to the airport storage facility. ARB should make this clear in the final rulemaking. (WSPA2_61-7a)

Comment: 6. Reword Section 95483(a)(1)(C)

The language in the above-reference paragraph is confusing and appears to overlook the fact that Alternative Jet Fuel must be blended with conventional jet fuel, which may take place at an interim facility. We recommend the following clarification:

Specifics for Alternative Jet Fuel. For an alternative jet fuel or the alternative jet fuel portion of a blend with conventional jet fuel, the first fuel reporting entity is the producer or importer of the alternative jet fuel first delivered to either (1) a blending facility; or (2) a storage facility where alternative jet fuel is stored before blending, or a blended fuel is stored before being uploaded to an aircraft in California. Conventional jet fuel, including the conventional jet fuel portion of a blend, is not subject to the LCFS and must not be reported. (LANZATECH1_77-8)

> **Agency Response:** Staff disagrees that the point of credit generation should be the refinery gate in the case of renewable jet fuel produced by co-processing renewable feedstocks at refineries and disagrees that the paragraph in the regulation language appears to overlook the fact that AJF must be blended with conventional jet fuel, which may take place at an interim facility. The approach that staff proposed is similar to that taken for all other liquid fuels. For all low carbon alternative liquid fuels, the producer or importer is the most logical entity to designate as the first fuel reporting entity with the right to generate credits because either they are the party that directly incurs the cost of constructing and operating the alternative fuel production facility that the LCFS is trying to incentivize, or, in the case of importers, they are the closest Californian entity in the supply chain to that producer. Moreover, the alternative jet fuel portion of a blend with conventional jet can be tracked separately under the LCFS accounting system in a similar manner to the separate tracking of biodiesel and diesel in blends of these fuels. However, staff acknowledges that the paragraph may be confusing, so the paragraph was updated during the first 15-day change for clarity.

D-1.9. *Energy Density*

Comment: 4. Add an energy density for fossil jet to Table 4

All fuels except for Alternative Jet Fuel have both the fossil baseline energy density and the alternative fuel energy density listed in Table 4. For jet fuel only the Alternative value is listed. Per ASTM, the minimum fossil jet energy density is 42.8 MJ/kg, while the average is 43.2 MJ/kg. Using an average density of 0.8 kg/L (6.67 lb/gal) gives a minimum energy density of 129.6 MJ/gal and an average of 130.8 MJ/gal. (LANZATECH1_77-6)

> **Agency Response:** Staff disagrees with this recommendation. Since conventional jet fuel is not subject to the LCFS, an energy density is not needed in Table 4.

D-1.10. *Change of Referenced Fuel in Table 5*

Comment: 5. Relabel "biomass-based jet fuel" as "Alternative Jet Fuel" in Table 5

There is no definition for "biomass-based jet fuel". This reference should be relabeled "Alternative Jet Fuel". (LANZATECH1_77-7)

> **Agency Response:** In response to this comment, staff modified the Regulation language from "Jet fuel or Biomass-based jet fuel blends" to "Alternative Jet Fuel."

D-1.11. *Infrastructure Development*

Comment: Further, airports will continue to face infrastructure critical for AJF development and funding needs. And even with the support of the LCFS credit, those credits are not applicable to the infrastructure development needs at the airport, and other stakeholders will need to in order to fund and accommodate AJF at our airports. So we hope that some day funds will be available to help airports close this gap. (SFO2_T17-3)

> **Agency Response:** The comment recommendation goes beyond the of scope of this rulemaking because the issue discussed is not incorporated in the proposed revisions or included in the notice of changes.

D-2. *Propane*

D-2.1. Multiple Comments: *Support for the Proposed Propane Provisions*

Comment: REG strongly supports the addition of … renewable propane as opt-in fuels… (REG1_88-5b)

Comment: REG supports the drafted rules for … renewable propane. In addition, we agree that CARB should not require entities buying below the rack to report to LRT-CBTS unless they export the fuel. (REG1_88-8a)

Comment: The WPGA strongly supports the inclusion of propane as a fuel under the LCFS. (WPGA1_121-1)

> **Agency Response:** Staff appreciates the support for the inclusion of propane in LCFS.

D-2.2. *Opt-in Party and Regulated Party*

Comment: We are not in favor of making propane a regulated fuel by default. Propane represents a very small segment of the transportation fuel market and its inclusion would not have a material effect on the goals of the LCFS. The proposed change makes an already complicated program more complicated by adding a new population of regulated parties who must now adapt their business models to address the cost and

administrative burden of a new LCFS obligation. Credits should be available for renewable propane due to its lower CI, but participation in the program should be voluntary for producers as that would be far less disruptive to the market. (CHEVRON1_112-5)

> **Agency Response:** Staff disagrees with the recommendation to include all fossil propane in the LCFS only as an opt-in fuel. As a higher CI alternative fuel, fossil propane will eventually generate deficits. Staff believes that including fossil propane in section 95482(a) is consistent with treatment of other fuels with carbon intensity pathways that do not outperform the compliance schedule benchmarks set forth in section 95484.
>
> Mandatory participation for fossil propane starting in 2019 will promote the transition to low CI renewable propane. Further, to adjust small stations selling fossil propane into the LCFS gradually, staff proposed an exemption from LCFS for stations with total throughput of 150,000 gasoline-gallons equivalent or less per year. The exemption for fossil propane dispensing stations expires January 1, 2021 as the fuel becomes deficit-generating in some applications at that point.

D-2.3. ***Energy Economy Ratio for Propane***

D-2.3a. Multiple Comments: ***Energy Economy Ratio for Indoor Forklifts***

Comment: II. Indoor Propane Forklifts Do Not Displace Gasoline or Diesel Forklift Use

Another issue of concern involves CARB's assumption that displacement of gasoline or diesel occurs with use of propane forklifts in indoor settings (e.g. warehouses, distribution centers, big-box stores). Indoor forklifts require clean burning fuels such as propane. CARB has assigned an EER value of 3.8 for electricity for forklift applications; however, such forklifts do not displace gasoline or diesel because these fuels are not used in indoor applications.

Since neither electric or propane indoor forklifts displace gasoline or diesel, these applications should not be included in the LCFS. And if they are to remain in the LCFS, propane should not receive an EER of 0.9 as it has been the fuel of choice in indoor forklifts and does not compete against diesel. Inclusion of the 3.8 EER for electric indoor forklifts is clearly not consistent with CARB's stated mission of diesel and gasoline displacement—and not the displacement of propane. Further, CARB's characterizing propane forklifts used indoors with an EER of 0.9, on the basis that they would otherwise operate on gasoline or diesel, acts to penalize propane at the same time it contradictorily discourages development and advancement of low-carbon fuel options.

…

- Propane forklifts should not be accorded a lower-than-appropriate EER (0.9 as now proposed by CARB) on the mistaken assumption that they displace gasoline

or diesel lifts, since indoor propane forklifts operate where gasoline and diesel lifts are prohibited. (WPGA1_121-3)

Comment: My comments, which have been outlined in our letter we submitted, specifically focus on a couple of key areas. The first is that of forklifts. Since we're new to the program, I'm not sure initially when forklifts were included in the program, if there was a primary look at all propane -- all forklifts indoor and outdoor having kind of the same fuel sources. But if you look at forklifts today, indoor forklifts -- you'll be very hard pressed to find any indoor forklifts that operate with gasoline or diesel. So if the purpose of the LCFS is to replace or displace gasoline and diesel, we recommend that there's a bifurcation, if you will, between indoor and outdoor forklifts used. Indoor forklifts again primarily run on alternative fuels, not gasoline or diesel. (WPGA2_T27-1)

> **Agency Response:** The comments from WPGA imply a propane benchmark could be a more appropriate point of crediting for indoor forklift applications. Under such an approach electric forklifts, for example, would be assigned slightly less credit and propane forklifts would be assigned zero credit. Because staff was not able to quickly develop a method to divide forklift fleets between indoor use (where the commenter asserts that gasoline and diesel displacement is unlikely) and outdoor use, staff could not introduce such a nuanced approach in the current rulemaking, but may explore proposing such an approach in a future rulemaking.

D-2.3b. ***Propane Displaces Gasoline, Not Diesel***

Comment: III. Propane Onroad Trucks and Buses Primarily Displace Gasoline, Not Diesel

Propane vehicles in CA operate in several market niches in medium duty applications. Airport shuttle bus, school bus, and transit bus fleet operators routinely choose to not purchase diesel vehicles for a number of reasons. It is well known that 2010 onroad diesel tailpipe emission standards have resulted in greater diesel vehicle purchase and repair costs, and with reduced duty-cycle flexibility (particularly in stop-and-go settings and lower load or temperature profiles that can lead to DPF failure). Airport shuttles routinely operate in in highly competitive, contracted settings where higher diesel vehicle and repair costs are simply not tolerated. In addition, shuttles and buses routinely operate in areas sensitive to diesel exhaust exposure, including multi-level airport structures and with daily transporting school children between home, school, and offsite school events. Public transit operations have similarly rejected use of diesel vehicles, purchasing lower-emitting propane or other alternatively-fueled bus options[3]

[3] San Diego Metro Transit System operates 77 propane buses; according to MTS' Michael Wygant, diesel buses were simply not a viable option.

Propane vehicles primarily compete in the Class 4-6 markets, where, contrary to CARB LCFS staff's assumption that all heavy-duty (≥ 14,000 lb. GVWR) onroad vehicles in CA will operate as diesel vehicles, they displace <u>gasoline</u> vehicles. Because of the discrepancies in diesel, gasoline, and propane heavy-duty vehicle EER values proposed by CARB staff, one option would be for CARB to assign all gasoline

heavy-duty vehicles an EER of 0.9; this would effectively eliminate the fuel displacement issue. Absent this option, CARB should add a Class 4-6 option for propane vehicles displacing not diesel, but gasoline. We invite CARB to review our previously submitted comments on the displacement of gasoline by propane vehicles, as well as the photos provided at the end of this letter.

…

- Propane engines operating in Class 4 – 6 vehicles displace gasoline engines in the supermajority of cases. (WPGA1_121-4)

  Agency Response: Staff understands the commenter's request for greater disaggregation of gasoline vs. diesel vehicle displacement and acknowledges that the type of fuel displaced may be complex to determine in certain applications. However, staff believes the commenter's recommended change would require an overhaul of the EER table for all vehicle-fuel combinations to ensure equitable treatment of all fuels used in Class 4-6 vehicles. This task would require a comprehensive update to engine technologies used in such applications. Such an analysis was not included in how staff initially scoped this rulemaking. Therefore, staff will study this subject and will consider updating the EER table in future rulemakings to address this comment.

D-2.3c. Multiple Comments: *EER Determination for LPG Buses*

Comment: The 2018 ISOR contains an extensive discussion of LPG bus fuel economy and the EER values relative to diesel and gasoline buses based on the testing done at the Altoona Bus Testing Center. The tests include dynamometer tests using the Manhattan cycle (6.8 mph average speed), the Orange county cycle (12.0 mph) and the Urban Dynamometer Driving Schedule (18.9 mph). Tests were also conducted on the test track using cycles labelled CBD (12.8 mph) Arterial (27 mph) and Commuter (38 mph) test cycles. In both the dyno and track tests, the HVAC system was turned off. In addition, the test cycles used for the track tests do not resemble normal driving in that the cycles consist of a simple pattern of steady accelerations cruise at constant speed, and steady deceleration to idle.

Hence, the loads on the test track cycle do not resemble those for the dyno tests, and there is significant reason to doubt test track results between different engine types (spark ignition vs. diesel) would yield EER values consistent with real world values. This is particularly true given that the track data also appeared to contain more errors than the dyno data. For example, the fuel economy measured on the Commuter cycle (which is essentially a constant speed cycle at 40 mph with 2 stops) was worse than the fuel economy measured on the UDDS cycles (with numerous stop-and-go events and a speed of 18.9 mph) on the dyno for many of the vehicles in the ARB database. These data would contradict the fact that fuel economy of conventional vehicles is typically highest at 40 to 50 mph constant speed conditions.

Figure 2 taken from the ISOR shows the EER values computed for three different LPG vs. diesel vehicle pairs labelled as "trolley", "upfit" and "school bus". The EER trend for the trolley with increased cycle average speed shows a different trend than those for the other two types, where the propane vehicle EER decreases with increasing speed.

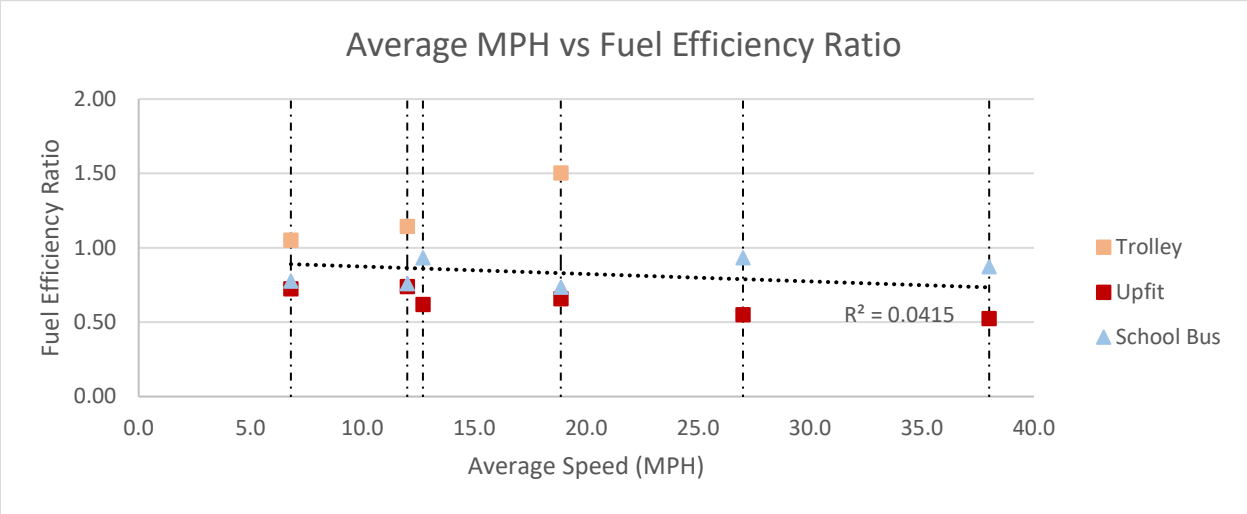


Figure 2: EER of Propane Buses relative to Diesel Buses

An examination of the data showed that mixing the track and dyno results could mask the real trends in the EER, and that the diesel trolley bus chosen for comparison had unusual fuel economy trends on the dyno compared to the trends for other vehicles. If the other trolley excluded by ARB in its analysis (for its test weight being about 20% heavier) is chosen for reference and the EER discounted by 20% (as a 1% increase in weight decreases fuel economy by approximately 1% in slow speed stop and go cycles), a more comparable set of figures emerge as shown below:

Test Type	Cycle	Trolley	Upfit	Bus
Dyno	Manhattan	0.83	0.72	0.78
	Orange	0.79	0.74	0.76
	UDDS	0.70	0.66	0.74
Track	CBD	0.90	0.62	0.93
	Arterial	0.93	0.55	0.93
	Commuter	1.02	0.52	0.87

While the data still shows some scatter, the low speed cycle data on the dyno suggest a propane bus EER of 0.74 for urban cycles. The high-speed arterial and commuter cycle data from the test track show a significant discrepancy for the "upfit" vehicles and the

data on the diesel upfit vehicles on the test track was difficult to reconcile against their performance on the dyno tests. One upfit diesel vehicle showed higher mpg on the dyno UDDS cycle than on the 38 mph commuter cycle which has only two stops and extensive cruise at 40 mph, and this appears unlikely in real world driving. Ignoring the upfit EER results would suggest an EER of 0.9 to 0.95 for higher speeds. The higher EER at higher speeds is also consistent with the narrowing efficiency differential between s.i. engines and diesel engines at higher speeds and loads.

The ARB has also estimated an EER of 1.0 for a propane bus relative a gasoline bus at urban speeds. Note that this is quite consistent with an EER of 0.74 for a propane to diesel bus comparison as the diesel is known to be 25 to 30 percent more efficient relative a gasoline engine at urban speeds. (GROWTHENERGY1_B4-80)

Comment: The EER values for propane buses derived from Altoona Bus Testing Center data rely on tests that do not resemble real world use. An EER of 0.74 may be appropriate for propane buses but this needs confirmation on tests with the bus HVAC system operating normally. (GROWTHENERGY1_B4-87)

Comment:

EER Summary

Vehicle Type	EER recommended by ARB	Suggested Correction
LPG Bus	0.9	0.74 at urban speeds (<20 mph)

(GROWTHENERGY1_B4-96)

Agency Response: Staff recognizes that the operation of a vehicle would, at times, result in the HVAC system being in its operational state. Staff also recognizes that the regimented structure of the CBD, Arterial, and Commuter test cycles conducted on the test track is not entirely reflective of normal driving habits and that the dynamometer testing cycles bear a closer resemblance to real-world driving. It should be noted, however, that no test perfectly replicates normal driving cycles and that the propane EER study is not intended to compare or determine fuel efficiency between different average speeds. The Altoona testing data was used in the EER study primarily to compare the performance of two separate fuel technologies given identical test cycles. As such, the results from comparing data is appropriate in determining the EER of propane versus diesel fuel. The comparison of EER against average speed of the test is another example of extrapolation that is imperfect, but appropriate. The identifying trend between the tests at Altoona is the difference between the intended average speeds of the vehicle: An ideal set of results for a comparison of EER trends would require a singular test conducted at different average speeds under

identical conditions; this directly comparable data set is not yet available, therefore, staff used the data that was available.

Staff realizes that the diesel trolley data exhibited unexpected trends. However, the trolley in its base configuration was the most comparable vehicle to the propane trollies as tested. Without indication of any irregularities during testing, the results should not be dismissed. The validity of the Altoona testing is agreed upon as an industry standard, and it would be inappropriate to exclude the results from the analysis for displaying irregular trends.

Therefore, staff believes that it is appropriate to use the Altoona test data for propane EER study. An EER value of 0.9 was proposed for propane used as diesel replacement to be consistent with CNG and LNG, and it is within the range of results reported in the Altoona study. Staff would like to continue to work with stakeholders on this issue in future rulemakings if more data becomes available.

D-2.4. Multiple Comments: *Propane Fuel Specification Changes*

Comment: We are similarly concerned with very recent propane fuel specification changes proposed by CARB LCFS staff; these changes, if approved, will require reductions in propene (propylene) and butane content and will serve to discourage renewable propane refinery development. No "due process" information has been provided to justify either the need for these fuel constituent changes or the emission benefits they presumably are intended to provide, nor are they consistent with the propane fuel specification adopted by CARB in 1999 following more than a year of extensive private-public collaborations, analysis, emissions testing, and public review.

…

IV. Recent CARB LCFS Staff Proposed Changes to the Propane Fuel Specification Require Expanded Review and Public Input

CARB LCFS staff very recently proposed changes to California's propane fuel specification as they would apply to renewable propane, reducing both propene (propylene) and butane percentages from quantitative percentages established nearly 20 years ago following a year-plus long exhaustive private-public collaborative fuel specification study developed under the operation of the CARB-chaired Task Group.[4]

[4] Chaired by CARB, the 1999 HD-10 Task Group included SCAQMD, refiners, LPG industry members and associations, engine manufacturers associations, vehicle OEMs and product suppliers, the Canadian government, and the State of Texas. The Task Group was to identify LPG fuel blends that would meet or exceed emissions findings for test vehicles using certification LPG fuel; after many months of Group meetings and extensive project analysis and testing the propane fuel standard, which came to be known as "HD-10", was enacted by CARB following its approval by their Board of Directors on Dec. 11, 1999.

The extensive work resulted in the establishment of the propane fuel standard[5] allowing up to 10% propene and 5% butane and was predicated on emissions test data developed from both light-duty and heavy-duty vehicle test applications evaluated primarily under Test Method ASTM D 2163-87. Importantly, emissions controls and

tailpipe standards on passenger and heavy-duty vehicles have improved exponentially since 1999, yet no due-process evidence has been provided with CARB LCFS staff's recent proposed fuel quality changes to show why propane fuel quality acceptable for operational emissions certainty on those less robust emissions control systems is now unacceptable for modern vehicles that would use renewable propane.

[5] 13 CCR § 2292.6 governing propane fuel specifications and allowing up to 10% propene and 5% butane content in vehicle fuel was approved by CARB Board of Directors in the late 1999-early 2000 timeframe and is still in place today.

Renewable propane will provide very substantial carbon emission benefits over fossil propane, whether the renewable product is consumed as a 100% "neat" fuel or is in blend form with traditional fossil propane. Currently, renewable propane is produced as a secondary by-product, as a rate of only 5% or less of the total output in the production of renewable diesel. Testing provided during the Task Group's work in 1999 – 2000, which resulted utilized a vehicle propane fuel test blend containing 20% butane (by volume).

Without documentation supporting the recent CARB proposal, we infer that CARB is concerned with the potential for increased formation of NOx caused during engine pinging or knocking events. However, even with the propane test fuel containing 20% butane, its anti-knock index remained at over 100 (in comparison to the maximum value of 91 still applicable to today's highest octane-rated gasoline). Further, CARB should consider language permitting fuel blending of renewable propane containing 5% - 8% butane so long as the final product complies with the current standard (13 CCR § 2292.6).

In the absence of supporting documentation and public/private collaboration to justify the proposed reductions in propene and butane maximums in renewable propane, consistent with that applied by CARB and resulting in the formation and operation of a propane fuel specification Task Group in 1999, <u>we request that CARB staff accept the interim use of CA Vehicle Code section 380[6] as the renewable propane fuel specification</u>; this would provide important flexibility to the developing renewable fuel refining industry, and consistent with the essential objectives of the LCFS. Coupled with this, we request on behalf of WPGA and renewable fuel refiners working to support CA low-carbon objectives that CARB initiate a collaborative working group—this group would develop a renewable propane fuel specification, with increased opportunities for cost-effective carbon emission reductions while ensuring that tailpipe emission standards are met.

[6] CVC 380: "Liquefied petroleum gas means normal butane, isobutane, propane, or butylene (including isomers) or mixtures composed predominantly thereof in liquid or gaseous state having a vapor pressure in excess of 40 pounds per square inch absolute at a temperature of 100 degrees Fahrenheit".

In conclusion, the Western Propane Gas Association asks that CARB recognize that:

- Natural gas-based propane is the growing feedstock resource that will supply the increased demand for propane in vehicles, pending growing in renewable propane refining and output.

…

- Renewable propane would provide substantial carbon emission reduction benefits. It is highly improbable that CARB staff-proposed reductions in butane and propene content will, aside from leading to increased renewable-fuels refinery costs, provide improvements in actual tailpipe emissions or in durability and fitness of vehicle in-use emission controls.
- Renewable propane fuel specifications should adopt CVC §380 as an interim, pending development of specifications by a Task Group. Similarly, CARB should permit fuel blending of renewable propane (with higher constituent content) with traditional propane, with the final blend meeting, as necessary. (WPGA1_121-5)

Comment: My second most important comment for us is looking at the fuel specifications – and the spec for propane was established around almost 20 years ago – and specifically looking at the permissible butane content in propane. When we are looking at the producers for renewable propane, we find a slightly higher butane content. And we look forward to working with CARB staff to demonstrate the emissions profile even with the higher butane content would have a negligible, if any, impact to the emissions.

So having the acceptance of a higher butane content will enable us to have renewable propane in the program while transitioning from fossil to renewable. (WPGA2_T27-2)

> **Agency Response:** The provided comments are out of scope for this rulemaking. CARB staff did not propose propane fuel specification changes as part of this rulemaking. Propane fuel specifications are contained within 13 CCR section 2292.6.

D-2.5. ***Renewable Propane Fuel Specification***

Comment: Finally, we suggest potential modifications of the renewable fuel standard that will increase flexibility for refiners while ensuring that vehicle emission continue to meet applicable tailpipe standards and emissions durability requirements. (WPGA1_121-6)

> **Agency Response:** The recommendation goes beyond the scope of this rulemaking. The Renewable Fuel Standard is a U.S. EPA-administered program, not a CARB program.

D-2.6. ***Exemption and Phase-In Period for Removal of Opt-In Status for Small Station Dispensing Fossil Propane***

Comment: I also support the comments of Kevin Maggay for small station reporting operators exemption. We also have very small mom and pop stations. And so long as conventional fossil propane is below the cap and -- blow the threshold, we would also seek an exemption for those smaller station owners. (WPGA2_T27-3)

> **Agency Response:** Staff appreciates the commenter's insights and understands the concern that not providing an opt-in status for fossil propane in

initial years could pose challenge for small station operators to participate in the LCFS. To address this concern, as part of the 15-day changes, staff proposed to provide an exemption from LCFS requirements to any credit-generating fossil propane dispensed at a fueling stations with total throughput of 150,000 GGE or less in a year. The exemption for stations dispensing fossil propane under 150,000 GGE annually expires on January 1, 2021 when the use of fossil propane in heavy-duty applications would become deficit-generating in LCFS. This change would allow small station owners dispensing only fossil propane to maintain opt-in status until propane becomes a deficit generating fuel in the LCFS program.

Staff believes, several stations dispensing less than 150,000 GGE of fossil propane would continue to opt-in to receive the benefits offered by the LCFS program. Nevertheless, the proposed change would provide small propane station owners the flexibility to defer opting-in if they choose so in order to better plan their participation in the LCFS program.

D-3. *Fossil Compressed Natural Gas*

D-3.1. Multiple Comments: *Exemption and Phase-In Period for Removal of Opt-In Status for Small Station Dispensing Fossil Compressed Natural Gas*

Comment: Fossil CNG is expected to be a credit generating fuel till 2025. However, the amendments require that all CNG users are going to have to report their use in 2019, which is a full six years before it becomes a deficit generating fuel. That's a long period of time to report before it crosses over.

Which in a sense isn't really a big problem because most of the large users have already opted into the program, and that accounts for the majority of the total volume of fuel.

Our concern is with the smaller users and the smaller station operators. These are small businesses, mom and pop shops, very small municipalities. Our concern is that they won't have the wherewithal, the resources, or even the motivation to take on the administrative burden of the program. They'll end up doing what might be the easiest thing for them and, that is, switching back to petroleum fuels; which, as Richard Corey mentioned in his opening remarks, the use of alternative fuels has exceeded all expectations, and it would be a shame for users to go backwards at this point.

We've proposed to staff an exemption for small users through 2025 while fossil CNG is still a credit generating fuel. We think that the exemption period would provide the natural gas industry and ARB to work together to consolidate and streamline the reporting; but more importantly, to develop products and services that would take these CNG users and move them from fossil CNG to renewable natural gas which achieves the highest -- or actually the lowest carbon intensities of any fuels of any of the different pathways. (SCG2_T20-2)

Comment: LADWP understands that the proposal to remove the opt-in status of fossil CNG is based on the CARB's anticipation of most fossil CNG pathways becoming deficit generating pathways in the 2020-2030 timeframe. LADWP is a CNG fuel provider to its own fleet with a limited number of consumers.

The proposal for CNG fuel to become a deficit-generating fuel conflict with LADWP's and other public fleets' compliance with South Coast Air Quality Management District (SCAQMD) Rule 1196, *Clean On-Road Heavy-Duty Public Fleet Vehicles*. This rule requires public fleet operators to acquire alternative fuel heavy-duty vehicles when procuring or leasing these vehicles. LADWP acquired CNG vehicles and installed CNG fueling stations to comply with Rule 1196. At the time of acquisition, there were no commercially available zero-emission medium-heavy-duty vehicles. In the latest *Final 2016 Air Quality Management Plan*, according to SCAQMD staff,

> "Fleets will be encouraged to acquire near-zero emission medium-heavy-duty vehicles in the near-term to help meet federal air quality standards by 2023 where there are no commercially available zero-emission medium-heavy-duty vehicles or zero-emission vehicles that are commercially available, but cannot be used in certain vocations."

LADWP recommends ARB allow regulatory flexibility to entities with small CNG operations of special uses or under certain circumstances (i.e. subjected to Rule 1196). The requirement for mandatory reporting and third-party verification, and cost burden associated with the proposed compliance obligations will likely hinder future investments in alternative fuel vehicles. LADWP recommends amending the applicability of the proposed exemption in section 95482(d)(3), which states "Any deficit-generating fossil propane and CNG used in school buses purchased prior to January 1, 2020," to **school buses or public fleets with fuel for transportation use at an aggregated quantity of less than 42 million MJ (360,000 gasoline gallon equivalent)[1] per year.** Alternatively, an exemption can be added to section 95500, similar to section 95500(b)(2)(B) Less Frequent Verification, where the CNG fuel pathway is exempt from verification if the quantity of fuel produced and reported by any entity does not result in more than *2,000*[2] credits generated in LRT-CBTS during the prior calendar year.

[1] 10% of limit for exemption for specific fuels in section 95482(c)(1)(B).

[2] One-third of the limit in section 95500(b)(2)(B).

(LADWP1_38-4)

Comment: <u>SoCalGas recommends providing an exemption for small compressed natural gas (CNG) station operators that have not yet opted in to the LCFS Program and dispense less than 1.25 million gasoline gallon equivalent units until fossil CNG becomes a deficit generating fuel in 2025. This is equitable since these CNG station operators will not create a deficit until 2025 and will allow industry adequate time to develop and provide LCFS administration and related products and services for small CNG station operators that will encourage the continued and expanded use of low carbon fuels including Renewable Gas.</u>

Staff is proposing to convert fossil CNG from an opt-in fuel to a mandatory reporting fuel under the LCFS program. Based on information provided by ARB staff, it is expected that CNG will not become a deficit generating fuel until January 1, 2025, leaving approximately seven years of use as a credit generating fuel. Larger, more sophisticated CNG users have largely opted into the program to take advantage of the benefits, however hundreds of smaller CNG users have not opted in.

While credit generation creates a declining financial benefit through 2025, we are concerned with the sudden administrative burden that would be imposed on these smaller CNG users. It is likely that this administrative burden and the fear of generating deficits in 2025 may push these smaller users back to higher carbon intensity, petroleum-based fuels. This is the type of negative outcome the amended LCFS regulations should avoid.

We have worked with ARB staff to gather information on smaller CNG stations. Based on information provided by ARB staff and an initial analysis of utility billing data, it appears that at most, a very small percentage (14 percent) of the total volume of natural gas supplied to CNG vehicle refueling stations are for operators that have not yet opted in to the LCFS Program. Additionally, the operators that have not yet opted in to the LCFS Program represent 61 percent of the number of CNG vehicle refueling stations. On average, operators of CNG vehicle refueling stations that have not yet opted in to the LCFS Program use ten times less than CNG vehicle refueling stations that have opted in. Thus, it is small operators of CNG vehicle refueling stations, consisting of school districts, municipalities, and small businesses that have not yet opted in to the LCFS Program.

An exemption for these smaller users would not have an environmental effect on the program as the exemption would only apply while CNG is a credit generating fuel. In addition to helping the smaller users, an exemption would also have the following benefits:

- Retain Low Carbon Fuel Users. It is likely that small users would not have the resources or desire to report to the LCFS for the relatively low financial benefit associated with fossil CNG. Instead of dealing with the reporting, we are concerned that users would abandon alternative fuels altogether. An exemption would help to retain CNG users rather than potentially moving back to petroleum based fuels, which would be counter to the intent of the program.
- Decrease Administrative Burden for ARB. By allowing industry time to develop products and services to take on the administrative burden on behalf of the hundreds of users, it would drastically reduce the administrative burden for ARB. It would reduce submittal review as well as reduce the enforcement burden.
- Increase Data Accuracy. Working with industry, as opposed to hundreds of less experienced small operators, would increase the accuracy of reporting as industry professionals have the wherewithal and resources to accurately report the required information to ARB in a timely manner.

- Increase Outreach and Data Collection Options. ARB would have the opportunity to leverage utilities to get assistance with LCFS Program outreach, gather aggregate market information to help guide policy decisions, and assist small operators to voluntarily opt in to the LCFS Program.
- Increase the use of Renewable Gas. Lastly, and most importantly, with the ability to act as an aggregator and subsequently being able to procure gas on behalf of smaller users, industry can promote and encourage the move from fossil CNG to Renewable Gas, which can achieve the most carbon reductions of any fuels available, in some cases being carbon negative depending on the feedstock. Based on information provided by ARB staff, almost two-thirds (62 percent) of natural gas fuel reported to CARB through the LCFS Program at the end of 2016 was Renewable Gas[1]. Providing industry time to provide additional Renewable Gas related products and services to customers already using CNG without additional administrative hurdles would significantly help to achieve the goals of the program.

[1] https://www.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm

(SCG1_75-1)

Comment: Page II-6: The Staff Report proposes to remove the opt-in status of fossil compressed natural gas (CNG). The biogas market has significant potential to expand over the next few years due to the organic waste disposal reduction mandated by Senate Bill 1383 (Chapter 395 of the 2016 State Statutes) and its implementing regulation, which focuses on anaerobic digestion (AD) technologies and processes to generate biogas/biomethane. Additionally, as monetary incentives for biomethane pipeline infrastructure projects become available pursuant to Assembly Bill 2313 (Chapter 571 of the 2016 State Statutes), it is important that the existing infrastructure for natural gas be properly maintained to provide short-term storage for biomethane and increase access to biomethane for transportation fleets and other end users. As such, the Task Force strongly believes that CARB needs to extend the phase-out of fossil CNG to allow the biogas market to expand to make use of the existing infrastructure and avoid discouraging investments in gas pipeline infrastructure until additional in-state infrastructure is developed to provide for the state's needed renewable CNG. (TASKFORCE1_89-2)

Agency Response: Staff appreciates the commenters' insights and understands the concern that proposed removal of opt-in status for fossil CNG could pose challenge for small station operators to participate in the LCFS. To address this concern, as part of the 15-day changes, staff proposed to provide exemption from LCFS requirements to any credit-generating fossil CNG dispensed at a fueling stations with total throughput of 150,000 GGE or less in a year. The exemption for stations dispensing fossil CNG under 150,000 GGE annually expires on January 1, 2024 when the use of fossil CNG in heavy-duty applications would become deficit-generating in LCFS. This change would allow small station owners dispensing only fossil CNG to maintain opt-in status until CNG becomes a deficit-generating fuel in the LCFS program.

Staff believes several stations dispensing less than 150,000 GGE of fossil CNG would continue to opt-in to receive the benefits offered by the LCFS program. Nevertheless, the proposed change would provide small CNG station owners the flexibility to defer opting in if they choose so in order to better plan their participation in the LCFS program. See Response O-6.3 in this chapter regarding verification thresholds and exemptions.

D-4. *Renewable Natural Gas*

D-4.1. Multiple Comments: *Support for the Proposed Amendments to the Renewable Natural Gas Provisions*

Comment: The LCFS Program is critical to successful implementation of CARB's Short-lived Climate Pollutant (SLCP) Strategy and the desired reduction in dairy methane emissions. Without a viable long-term LCFS market, dairy methane reduction efforts will fall far short of the state's goals.

….

AECA is particularly interested in proposed LCFS reforms that will lead to greater opportunities for biomethane fuels, which currently account for just 7 percent of LCFS credits. A robust LCFS that encourages biomethane as an alternative carbon-negative transportation fuel is critical to the successful implementation of the state's SLCP strategy generally and its dairy methane emission reduction targets specifically. (AECA1_72-1)

Comment: In conclusion, AECA appreciates the opportunity to offer these comments on the Proposed LCFS Regulations. We look forward to their consideration by CARB and to ongoing efforts to expand and encourage in-state development of biomethane under the LCFS program. As a result, AECA supports the need to develop a sustainable and stable long-term LCFS market. (AECA1_72-13)

Comment: And I encourage you to continue to take the necessary actions to ensure that biomethane continues to be a source that California can use as a benefit for our residents today and future generations.

As Julia said, and implement the suggestions that she submitted.

We'll continue to produce this waste. And we have it in our power to go ahead and move forward.

I would ask you to view biomethane for what it is. It's our ability to not only drive the economy, but clean our air. And I believe it's one of the best ways of any source to do so. (GLB1_T22-2)

Agency Response: Staff appreciates the commenters' support for the proposed amendments to the renewable natural gas provisions. Staff believes these changes would further promote use of renewable natural gas as a low carbon

transportation fuel. Staff acknowledges the commenter's assertion that the LCFS supports the state's methane reduction goals. Staff believes that the LCFS provides substantial economic benefits to biomethane fuels, especially those that achieve low or negative CI values, and expects that these economic benefits, along with several changes to streamline and facilitate LCFS participation, will incent greater adoption of methane capture projects on dairy and livestock farms. Staff further recognizes the importance of market certainty in sending the long-term investment signals in low carbon fuels.

D-4.2. Multiple Comments: *Renewable Natural Gas Sources from Outside California*

Comment: Moreover, according to CARB, renewable natural gas accounted for just 68 percent of all fuel used in natural gas vehicles, however, most of this RNG was from sources outside of California. Going forward, CARB must do a better job of ensuring California produced biomethane achieves significant market penetration by taking the steps necessary to encourage its development and use. Reducing SLCPs at the levels targeted by CARB will necessitate in-state production from feedstocks including diverted organic waste and livestock manure. Out-of-state projects provide little, if any, direct SLCP reductions to meet the state's requirements. As a result, the LCFS program is currently providing a subsidy or windfall to out-of-state RNG production at significant cost for California consumers. This out-of-state RNG is also flooding the market to the exclusion of RNG produced here. (AECA1_72-3)

Comment: We're particularly interested in proposed LCFS reform that will lead to greater opportunities for in-state biomethane. I want to underline in-state. We really need to get this program focused on in-state, not out-of-state biomethane the 90 percent that Ms. Kapoor just referenced. It's not coming from California. The overwhelming majority of that is coming from out of state. We need to get it focused here.

We've got 18 to 20 new dairy digester projects that are currently in various stages of construction. All 18 of the ones funded by CDFA are transportation fuel projects, which means they're going to be dependent on the LCFS going forward. So it's critical. CDFA is going to soon approve another 30 to 40 more dairy digesters in California. This is part of a $260 million investment of GGRF that the State is going to be making that's going to be matched by about $750 million from the dairy industry, and our partners.

So it's about a billion dollar investment and it's going to be dependent on LCFS. So it's really critical that we make sure that this program works for in-state projects going forward. It's the highest and best use. It's not only going to help achieve short-lived short climate pollutant reductions. It's going to help us reduce criteria pollutants in the San Joaquin Valley by displacing diesel fuel.

Biomethane currently only accounts for seven percent of the LCFS credits, 68 percent of the renewable natural gas being used in natural gas trucks today is RNG. And virtually all of that is coming from out of state. Those projects do not provide short-lived

climate pollutant benefits here in California. And we need to get those co-benefits of the short-lived climate pollutant while we're getting our LCFS credit.

So this needs to change as we move forward.

…

So it's a good relationship. It can only get better, but we've got to really focus LCFS on dairy methane. (AECA2_T44-2)

> **Agency Response:** Staff acknowledges that historically the majority of RNG used in California vehicles is from sources outside of California. This demonstrates that the LCFS does not discriminate between in state and out of state fuel producers based on their geographic location. The proposed changes in this rule continue to encourage RNG projects both inside and outside of the state.
>
> However, fuels produced in California may have GHG benefits that are reflected in the life cycle CI methodology used under the LCFS. For example, RNG pathways include the emissions from energy use and methane leakage that occur during pipeline transmission; as these are each distance-dependent parameters, RNG sources that are nearer to California refueling stations may be able to achieve lower CI values than out-of-state sources in some cases. The CI values also reflect the benefit of a lower electric grid carbon intensity in California than many other regions.

D-4.3. *Dairy and Swine Manure Crediting*

D-4.3a. Comment: According to the Manure Management Operations "draft" Guidance Document of 12-12-17, ARB is clear that a project is eligible to receive the full value of the CI for one crediting period, if the project began prior to the implementation of regulation of dairy methane. By way of example, if a project begins operation on 1-1-21 and regulations go into effect 1-1-25, the project would be eligible for its full CI value for the full crediting period (of 10 or 11 years based on the duration of the first reporting period). Similarly, if the regulations do not go into effect until 1-1-32, the project would be eligible for the full CI for two credit periods and thus through the end of 2040.

As it relates to carbon offsets we understand and concur with this approach. However, for LCFS credit generation, we ask that ARB reconsider this structure. As currently contemplated a project may benefit from a second 10-year crediting period and the stable long-term revenue streams that would accrue, however it cannot plan accordingly. AECA is seeking the distinction between cap and trade and the LCFS because electricity projects (in California) are eligible for 15 and 20-year electricity PPAs, and one 10- year crediting period, providing them with long-term certainty. Two 10-year crediting periods for biomethane projects will create a more balanced playing field and further encourage these transportation fuel projects with their associated local environmental benefits. (AECA1_72-10)

Agency Response: Staff would like to note that the crediting period initially discussed in the draft guidance to which comment AECA1_72-10 refers was added to the proposed modified regulation in a 15-day change period. As the commenter notes, this provision was designed to be identical to the crediting periods available to offset projects under Cap-and-Trade.

Under the proposal, qualified projects are eligible for a CI that reflects avoided methane for their initial 10-year crediting period, with the opportunity to apply for up to two subsequent 10-year crediting periods, or until a law, regulation, or legally binding mandate comes into effect requiring such controls. Since the guidance and proposed regulation do allow a second (and third) 10-year crediting period, staff interprets the commenter to mean an extension of the initial crediting period to 20 years. At this time, staff does not agree that an extension is necessary. At a range of current LCFS credit prices, staff believes that significant revenue potential exists to improve the economic return and viability of these projects. Nothing in the LCFS prohibits RNG producers from entering into long-term contracts for their fuel (analogous to electricity PPAs).

D-4.3b. Comment: The 12-12-17 Draft Manure Management Operations Crediting Guidance Document includes a chart (page 5) "Areas of the Livestock Protocol Not Applicable or Excluded from LCFS Requirements." The chart includes "Regulatory compliance requirements" referenced under the protocol Chapter 3.7.

Inclusion of this exclusion from LCFS Requirements is important in the Proposed Regulation. AECA recommends that CARB include this exclusion directly in the Proposed Regulation or by appropriate reference to the guidance document. This is an important consideration for informing project risk and capital sources. (AECA1_72-11)

Agency Response: Staff believes that it is unnecessary to add an exclusion in the LCFS regulation from the "regulatory compliance requirements" that are referenced in the Compliance Offset Protocol for Livestock Projects ("Protocol"). The LCFS regulation does not include such requirements, and projects are not required to adhere to the Protocol under staff's proposal. The Protocol's quantification method was relied upon in developing the proposed Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure; however, the Protocol itself is not incorporated into the LCFS regulation.

D-4.3c. Multiple Comments: ***Overlaps With Cap-and-Trade Compliance Offset Protocol***

Comment: 5. Projects should be allowed to claim both LCFS and Carbon Offset Credits, provided they do not claim both credits for the same fuel.

…

5. Projects should be allowed to claim both LCFS and Carbon Offset Credits, provided they do not claim both credits for the same fuel.

BAC appreciates the need to avoid double-counting of carbon reductions, but there is no need to prohibit projects from receiving both LCFS and carbon offset credits as long as they are not claiming both credits for the same fuel. Forcing projects to choose all of one or the other type of end use and credit will make compliance with the LCFS much more expensive and harder to meet the methane reduction requirements of SB 1383.

In many cases, biomethane projects will be most cost-effective if they use some of the biomethane or biogas for onsite power, heating or cooling, while some of it is used for vehicle fueling. For example, many wastewater treatment plants use the biogas that they produce for onsite power generation, but they have capacity to take diverted organic waste as well, often more cost-effectively than standalone facilities. In some cases, dairy digesters and other projects will be more cost effective if they use some of the biomethane produced for onsite power, heating or cooling, and use other biomethane for vehicle fuel. As long as individual projects provide adequate tracking and verification, there is no reason to force projects to choose this "all or nothing" framework where they must dedicate all the biomethane to either vehicle or to other end uses.

BAC urges ARB to revise this requirement to allow multiple end uses for biomethane so long as those end uses -and the credits that projects would otherwise be allowed by law to receive – are clearly tracked and verified. (BAC1_99-7)

Comment: The other one that actually wasn't in my comments, but I'll be submitting something in addition to that, it's also being able to bifurcate some of the fuel. We -- there are going to be some mixed projects where there may be some on-site energy production, and some gas going to transportation fuel.

And the way the proposal is currently written that's precluded. So we want to work on that as well. (AECA2_T44-4)

> **Agency Response:** The LCFS regulation places no limitation on the environmental attributes of a project that are not claimed under the LCFS or retired for compliance with LCFS. The LCFS recognizes any GHG reductions that are in the transportation fuel system boundary; thus, if biogas or biomethane is used e.g., to heat the digester or to produce thermal process energy or electricity for use in the gas upgrading facility, it can be recognized in the system boundary and reflected in the CI. However, biomethane that is captured and destroyed by flaring[5] or used to produce electricity that is sold to a utility (or otherwise exported beyond the system boundary), is excluded from the system boundary. The voluntary emission reductions that are not credited under the LCFS are not prohibited from claims in other jurisdictions or programs.

[5] Except the low-Btu gas referred to as "tailgas" separated from the product stream during biogas upgrading; destruction of methane in tailgas is included in the transportation fuel system boundary.

D-4.3d. Comment: However, we would like greater clarity on the requirements for the fuel pathway. To the extent CARB can offer clear directions, we expect to see more projects coming online. Some of the common questions include:

- If the dairy has a spill event, will it impact the carbon intensity score? (ECOENGINEERS1_B5-14)

  Agency Response: Staff recognizes the importance of regulatory clarity to support project development. If the commenter intended the term "spill event" to refer to an unanticipated leak or spill that could have other, non-GHG related impacts (e.g., impacts to groundwater quality), then staff's response is that only GHG emissions are considered in the determination of a fuel's carbon intensity score. The LCFS regulation does not include the regulatory compliance requirements of the Compliance Offset Protocol for Livestock Projects, Chapter 3.7.

  The LCFS method of determining CI relies on 24 months of operational data; in the event of an unanticipated release of methane, the pathway holder must accurately report the greenhouse gas emissions that occurred over the operational data period. If the certified CI is determined to have been exceeded, CARB will investigate and determine the appropriate adjustment to the certified CI and number of credits issued.

  Please note that staff also responded to this comment in the "Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations" (released September 17, 2018), but that response included a misleading typographical error. The LCFS regulation does <u>not</u> include the regulatory compliance requirements referenced under the Compliance Offset Protocol for Livestock Projects, Chapter 3.7.

D-4.4. *Organic Waste Diversion*

Comment: Page II-6: The Staff Report states that CARB anticipates that Renewable Natural Gas (RNG) pathways will continue to have carbon intensities (CIs) below the declining benchmarks set forth by these regulations and; therefore, RNG will maintain its opt-in status. The Task Force would like to know if the calculation for Low Carbon Fuel Standard (LCFS) credits for waste-derived RNG takes into consideration the amount of greenhouse gas (GHG) emissions that will be reduced by diverting waste away from landfills, and would like to be provided with a copy of analysis. (TASKFORCE1_89-1)

Agency Response: Staff's determination that RNG pathways will continue to have CIs below the declining benchmarks is based on existing certified pathways for RNG. RNG can be produced from many sources of organic material. When staff is able to verify that an applicant is diverting organic material (such as post-consumer food waste) away from landfills (i.e., using a feedstock that would be

disposed of by landfill in absence of the transportation fuel project), the CI does include the avoided methane that would have been released in the baseline scenario (landfill disposal). In response to public comments requesting a streamlined application method for biomethane (RNG) pathways, staff developed a Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Organic Waste which is publically available on the CA-GREET models webpage of CARB's website: https://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm.

D-4.5. Multiple Comments: ***Two Quarter Limit/Indirect Accounting of Renewable Natural Gas using Book-and-Claim Principle***

Comment: Per 95488.8 (i)(2), RNG injected into the common carrier pipeline can be reported as dispensed RNG without physical traceability within a two-quarter timespan. If a quantity of RNG is injected in one calendar quarter, the quantity claimed for LCFS reporting must be matched to natural gas sold as vehicle fuel in California no later than the end of the following calendar quarter. We believe that this two-quarter limitation is extremely constrained for dairy RNG projects and may cause business difficulties during the project registration period.

At the beginning of any dairy RNG project, three months of operating data must be provided to CARB to obtain a provisional CI. If facility commercial date of operation were to take place at the end of a calendar quarter, a producer then spends 3 months collecting data for the provisional pathway application while storing the produced RNG. This leaves a month or less to work with CARB to obtain provisional approval and begin to sell RNG in California before the project loses rights to its environmental attributes. This is an extremely short amount of time to work with CARB and obtain a provisional pathway. Furthermore, a project will have stored a significant amount of gas during the data collection period, and the full volume of this gas may not be able to be discharged in this time frame. **We recommend extending the time period that new projects are able to claim the environmental attributes using the book-and-claim method. We also recommend allowing projects undergoing an application for a provisional CI the ability to claim environmental attributes for their stored for the current calendar quarter and the following calendar quarter, beginning when the provisional CI is awarded to the project.** This will allow projects to retain full value of their environmental attributes for their stored gas for two quarters while mitigating any unexpected complications or delays that may arise during the registration process. (RNGC1_16-8)

Comment: The proposed amendments include a timing limitation to claim the environmental attributes of stored RNG, as outlined in 95488.8 (i)(2). According to the amendment, if a quantity of RNG is injected into the pipeline in one calendar quarter, the quantity claimed for LCFS reporting must be matched to natural gas sold as vehicle fuel in California no later than the end of the following calendar quarter. We think this two-calendar quarter limitation is extremely constrained for RNG projects and may cause business difficulties during the registration period.

At the beginning of any RNG project, three months of operating data must be provided to obtain a provisional fuel pathway. If the project begins commercial operations at the end of a calendar quarter, the three-month data collection period would occupy most of the subsequent quarter. This leaves a month or less to prepare the provisional pathway application materials and submit them to CARB. This is an extremely tight timeframe to work with CARB and obtain a provisional pathway before a project loses rights to its environmental attributes. Furthermore, a project will have stored a significant amount of RNG from production during the data collection period. Even if a provisional pathway is granted before the second calendar quarter ends, the full volume of stored RNG may not be able to be sold in the time remaining, resulting in a financial penalty to the project. In practice, this timing limitation will cause RNG producers to delay their projects in order to begin commercial operations at the beginning of a quarter, causing a delay in bringing RNG to the California market.

DTEBE recommends extending the time period that newly registered projects can claim the associated environmental attributes. We suggest that CARB consider extending the time period limitation to claim environmental attributes for newly registered projects. <u>RNG projects that are applying for a provisional pathway should be able to claim the associated environmental attributes for their stored RNG for the current and subsequent calendar quarters, beginning when a provisional pathway is awarded to the project.</u> This removes the financial risk of any unexpected complications or delays that may arise during the registration process. It ensures that CARB and the project owner can work together to obtain all the necessary project information during provisional pathway registration without the threat of sacrificing environmental attributes on any RNG that has already been produced during the registration process. (DTEBE1_56-2)

Comment: (4) *Proposed time limit for use of the environmental attributes from RNG.* We propose that any environmental attributes from RNG injected into a pipeline that are matched to a quantity of natural gas injected into physical storage be excluded from the current proposed time limit of two calendar quarters or alternatively, subject to a time limit of twelve months from the date the RNG is initially injected.

…

Section 95488.8(i)(2) of the Proposed Regulation provides that if a quantity of RNG is injected into the pipeline system during a calendar quarter, the environmental attributes associated with that RNG must be matched to natural gas sold as vehicle fuel in California no later than the end of the following calendar quarter. We respectfully request that the Proposed Regulation be modified to provide that to the extent the environmental attributes are matched with natural gas delivered (directly or indirectly) into physical natural gas storage within the same month as injection of the RNG into a pipeline, the environmental attributes associated with the RNG would be excluded from the proposed timing limitation entirely (or, if a limitation is required, eligible to be matched to natural gas sold as vehicle fuel in California with in twelve months of injection of the RNG into the pipeline). (EMRE1_B16-4)

Comment: Section 95488.8 (i)(2) allows for Book and Claim Accounting. "RNG injected into the common carrier pipeline in North America (and thus comingled with fossil natural gas) can be reported as dispensed as bio-CNG, bio-LNG, or bio-L-CNG, or as an input to hydrogen production, without regards to physical traceability."

However, the proposed regulation also requires that "Entities may report natural gas as RNG within only a two-quarter time span." Further, the two quarter period doesn't begin at COD but reflects calendar quarters. "If a quantity of RNG (and all associated environmental attributes, including a beneficial CI) is pipeline-injected in one calendar quarter, the quantity claimed for LCFS reporting must be matched to natural gas sold in California as RNG no later than the end of the following calendar quarter."

AECA believes this will likely result in significant problems during project start up putting critical revenues at risk of loss. We encourage CARB to extend the two quarter period to start after the provisional CI is determined or some similar solution. (AECA1_72-8)

Comment: Clean Energy requests that Staff clarify the book-and-claim provision for RNG in Section 95488.8(i)(2)(A) which states that a reporting entity must match a quantity of pipeline-injected RNG to California transportation fuel within a two-quarter time span. Clean Energy believes this two-quarter limitation for the recognition of environmental value should not apply to pipeline-injected RNG held in physical storage. All RNG projects are subject to lengthy project registration periods, especially at the federal EPA level with RFS and quality assurance plan (QAP) approval, which jeopardizes starting cash flow necessary for recouping up front capital investments. Furthermore, the LCFS regulation requires a minimum of three months of project operation before obtaining a provisional CI potentially leaving only one quarter for provisional pathway approval under this book-and-claim timeframe limitation. Project developers cannot afford to lose any environmental value associated with produced RNG, especially in the vulnerable start-up phase. In order to protect their value, most RNG developers secure storage agreements to deliver initial production of RNG to physical storage while project and pathway registrations are pending. Delivering initial RNG to storage ensures that the RNG producer can recognize the full environmental benefit of the RNG as a transportation fuel when the necessary registrations are final. Clean Energy requests that Staff add clarifying language to Section 95488.8(i)(2)(A) exempting any RNG delivered to physical storage from the limited two-quarter timeframe for recognition of environmental benefit. This will ensure that RNG producers will not unnecessarily lose value, reduce unintentional financial risk to the RNG project, and will keep the LCFS regulation aligned with the RFS in terms of recognition of environmental attributes. (CE1_92-11)

Comment: Allow for a minimum four quarter time span for Book and Claim for initial registration of Pipeline- Injected Biomethane Used as a Transportation Fuel

In Section 95488.8(i)2(A), ARB staff proposes that Entities may report natural gas as RNG within only a two-quarter time span. This Book-and-Claim methodology forces RNG produced and injected in a given quarter to claim LCFS credits by end of the following reporting quarter or risk loss of LCFS credits. AMP believes this constraint is

problematic for Tier 2 pathways that require significant modeling for approval of final pathways. AMP suggests that ARB allow for physical storage of gas using same requirements used by the EPA's RFS Program. AMP also suggests, at a minimum, ARB should allow for a four-quarter time span during the initial registration phase of a project and provide exemption from the book-and-claim requirement if there are significant registration delays. This will allow for project developers to have assurance that they will maximize financial benefits of their investment if there are unforeseen administrative delays. It also gives ARB and project developers time to resolve such delays that arise without negatively affecting financial performance of the project. (AMP1_86-3)

Comment: Dairy digesters offer the potential for CI values as low as -250g CO_2/MJ and can allow cost effective GHG reductions through existing CNG and refinery infrastructure. A number of proposed changes, together, are particularly detrimental to investors seeking to develop dairy digester projects. The proposed changes of concern include:

- A temporary pathway CI of 0 g CO_2/MJ for dairy and food/green waste to biomethane, whereas dairy-derived biomethane is known to have a much better CI (typically -250g CO_2/MJ, because of its unique methane emissions mitigation.)
- No retroactive credit generation based upon the CI submitted in a qualifying pathway application; rather, the CI of the default pathway (which is artificially high for dairy-derived biomethane) must be used until the provisional CI is approved by CARB. Excess credits would then retroactively added to the buffer account, but not benefit the project.
- Two-quarter limit on book-and-claim accounting (storage) of the biomethane, which will not allow sufficient time for the approval of a provisional CI before RNG must be withdrawn and used for LCFS credit generation.

The net result of these three provisions is that new dairy digester RNG projects will, during the critical initial period, be unable to generate LCFS credits representative of their GHG savings. Consider the following timeline:

- Initial data collection upon start of RNG injection: 3-4 months
- Data analysis and preparation of fuel pathway report: 0.5 -1 month
- Third party validation of fuel pathway report: 0.5 - 1 month
- CARB processing and approval of provisional CI: 2-3 months
- Dispensing the additional "surge" of RNG into CNG vehicles: ~ 6 months

Timeline from first injection until provisional CI approval is 6-9 months, and the clearing of the "surge" into the market will typically take another 6 months. The proposed rules only allow utilization of the -250g CO_2/MJ <u>after</u> CI approval date, however RNG injected in one quarter MUST be used for LCFS credit generation no later than the end of the following quarter (thus the period can be as short as 4 months). These constraints force

utilization of the default pathway of 0.0g CO_2/MJ, and severely impair the initial cash flow from projects that have legitimate CIs in the -250g CO_2/MJ range.

As a solution, we propose the following additional language to Section 95488.8(i)(2). Book-and-Claim Accounting for Pipeline Injected Biomethane Used as a Vehicle Fuel or to Produce Hydrogen:

- *For the purposes of book-and claim accounting of RNG produced from new projects that have not yet received a CARB-approved provisional or certified CI, for any RNG that is injected into the pipeline prior to such approval, the quantity claimed for LCFS reporting must be matched to natural gas sold in California as RNG no later than the end of the two following calendar quarters after the date of CARB approval of such CI. After that period is over, any unmatched RNG quantities from initial storage expire for the purpose of LCFS reporting.* (AJWIOGEN1_17-3)

Comment: Number 1: Dairy digesters offer the potential for carbon intensity values as low as negative 250 grams of CO2 and the co-benefit of meeting the state's short-lived climate pollutant goals. However, the draft ISOR may present some barriers to new projects. We would like to optimize the process for new dairy digester projects that will also help with the state's methane reduction. (AJWIOGEN2_T2-2)

Comment: Dairy digesters offer the potential for CI values as low as -250g CO_2/MJ, and can allow cost effective GHG reductions through existing CNG and refinery infrastructure. A number of proposed changes, together, are particularly detrimental to investors like Equilibrium Capital seeking to develop dairy digester projects. The proposed changes of concern include:

- A temporary pathway CI of 0 g CO_2/MJ for dairy and food/green waste to biomethane, whereas dairy-derived biomethane is known to have a much better CI (typically -250g CO_2/MJ, because of its unique methane emissions mitigation.)
- No retroactive credit generation based upon the CI submitted in a qualifying pathway application; rather, the CI of the temporary pathway (which is artificially high for dairy-derived biomethane) must be used until the provisional CI is approved by CARB.
- Two-quarter limit on book-and-claim accounting (storage) of the biomethane, which will not allow sufficient time for the approval of a provisional CI before RNG must be withdrawn and used for LCFS credit generation.

The net result of these three provisions is that new dairy digester RNG projects will, during the critical initial period, be unable to generate LCFS credits representative of their GHG savings. Consider the following timeline:

- Initial data collection upon start of RNG injection: 3-4 months
- Data analysis and preparation of fuel pathway report: 0.5 -1 month

- Third party validation of fuel pathway report: 0.5 - 1 month
- CARB processing and approval of provisional CI: 2-3 months
- Dispensing the additional "surge" of RNG into CNG vehicles: ~ 6 months

Timeline from first injection until provisional CI approval is 6-9 months, and the clearing of the "surge" into the market will typically take another 6 months. The proposed rules only allow utilization of the -250g CO_2/MJ) after LCFS pathway application approval, however RNG injected in one quarter MUST be used for LCFS credit generation no later than the end of the following quarter (thus the period can be as short as 4 months). These constraints force utilization of the temporary pathway of 0 g CO2/MJ, and severely impair the initial cash flow from projects that have legitimate CIs in the ~ -250g CO2/MJ range.

One solution would be for CARB to adopt a separate dairy digester RNG specific temporary pathway value. This CI value should be lower than 0 g CO2/MJ, perhaps in the -200 g CO2/MJ range. To avoid inappropriate use of this pathway, we would support reasonable requirements for the utilization of this temporary pathway. Examples could be:

- Farm-derived manure as the sole feedstock of the digester
- Limits on power and gas utilization per unit of RNG product

Another solution could be to modify the language in Section 95488.8(i)(2). Book-and-Claim Accounting for Pipeline Injected Biomethane Used as a Vehicle Fuel or to Produce Hydrogen . The following additional language would provide an acceptable means for us to recover LCFS value from a project's initial production:

- <u>For the purposes of book-and claim accounting of RNG produced from new projects that have not yet received a CARB-approved provisional or certified CI, for any RNG that is injected into the pipeline prior to such approval, the quantity claimed for LCFS reporting must be matched to natural gas sold in California as RNG no later than the end of the two following calendar quarters after the date of CARB approval of such CI. After that period is over, any unmatched RNG quantities from initial storage expire for the purpose of LCFS reporting.</u> (EC1_47-2)

  Agency Response: Staff appreciates the commenters' insights and understands the concerns associated with the proposed two quarter limit for book-and-claim accounting of renewable natural gas (RNG). To address the concerns, as part of the 15-day changes, staff proposed to extend the two quarter period for transferring renewable attributes of pipeline-injected RNG using book-and-claim accounting to three quarters.

  Staff believes this change provides increased flexibility to report injected RNG up to three quarters from the time of injection. This means, if a quantity of RNG (and all associated environmental attributes, including a beneficial CI) is

pipeline-injected in the first calendar quarter, the quantity claimed for LCFS reporting must be matched to natural gas sold in California as RNG no later than the end of the third calendar quarter.

As part of the 15-day changes, staff also proposed to revise the temporary CI value provided in Table 8 for biomethane CNG, LNG and L-CNG derived from dairy manure from 0 gCO_2e/MJ to -150 gCO_2e/MJ. Staff believes the proposed temporary CI value represents the higher end of the likely range of CI values that could be achieved and is likely to be sufficiently conservative for any dairy project avoiding methane emissions**.**

Staff believes these changes would provide sufficient flexibility to realize the value of CI reductions resulting from dairy projects avoiding methane emissions.

D-4.6. *Credit for More than One Use of Biogas or Biomethane*

Comment: We also strongly recommend that credit be given for more than one use of the biogas or biomethane that's produced, especially as wastewater treatment plants start to accept diverted food waste for co-digestion with solids and produce more biogas.

Right now we have existing useful life of assets that, you know, produce energy on site, and we would like the option to also produce low carbon fuel for nearby fleets.

And it helps offset the cost of ratepayers if we can look at different options for use of the biogas. (CASA2_T9-2)

Agency Response: Staff agrees with the commenter and would like to clarify that the proposed LCFS program amendments provide incentive for several uses of biomethane, including the use of biomethane in natural gas vehicles as a transportation fuel, in natural gas equipment as process energy, and in production of renewable hydrogen as a feedstock.

D-4.7. *Proposed Attestation Requirements for Renewable Natural Gas*

Comment: *(5) Attestations required in connection with RNG used as transportation fuel.* We provide proposed modifications to the Proposed Regulation intended to allow for the use of contracts and other documents in conjunction with attestations to collectively demonstrate the producer's exclusive rights to the environmental attributes associated with RNG.

…

Section 95488.8(i)(2)(C) of the Proposed Regulation requires that any entity pipeline-injected RNG reported as transportation fuel in LRT-CBTS must obtain and keep “attestations from each upstream party collectively demonstrating that (a) the entity claiming the environmental attributes has the exclusive right to claim environmental attributes associated with the sale or use of the biogas or biomethane,

and (b) the environmental attributes have not been used or claimed in any other program or jurisdictions with the exception of the federal RFS". We believe that requiring attestations as the only form of documentation is unnecessarily restrictive. Under the Renewable Fuel Standard program, documentation of a generator's rights to environmental attributes associated with RNG may be accomplished in a variety of ways, including through contracts and attestations.

Because Section 95488.8(i)(2)(c) specifies that the inability to promptly produce the attestations constitutes ground for credit invalidation pursuant to Section 95495, we respectfully request that the documentation requirement be modified to more clearly align with the documentation requirements of the RFS. We suggest the modifications shown below (additions or deletions relative to the Proposed Regulation are marked in underlined or strikethrough text, as applicable):

> *"An entity reporting any RNG as a transportation fuel in LRT-CBTS, and a fuel pathway holder using biogas or biomethane as process energy, must obtain and keep ~~attestations from each upstream party~~ documentation (including. without limitation. contracts or attestations) collectively demonstrating that (a) the entity claiming the environmental attributes has the exclusive right to claim environmental attributes associated with the sale or use of the biogas or biomethane, and (b) the environmental attributes have not been used or claimed in any other program or jurisdictions (with the potential exception of the federal RFS, as applicable)."*
> (EMRE1_B16-5)
>
> **Agency Response:** Staff disagrees with the commenter. The purpose of the attestations is to clearly demonstrate the transfer of the environmental attributes associated with the renewable natural gas between parties in the supply chain and to clearly identity which entity has the exclusive right to claim these attributes. The format and content pertaining to the ownership and movement of environmental attributes through the supply chain may differ significantly within contracts and other documentation making the review of such documentation difficult and administratively onerous. Therefore, it is critical to provide attestations for ensuring efficient review and maintain effectiveness of CARB's compliance audits and enforcement investigations, as well as the third-party verification program.

D-5. ***Hydrogen***

D-5.1. ***Book-and-Claim Accounting and Renewable Determination***

D-5.1a. Comment: Consider Existing Pathways that Currently Do Not Qualify for LCFS Credits

While renewable grid content contributes to LCFS credit values for plug-in electric vehicles, renewable hydrogen producers do not receive LCFS credits for the same electricity. This puts hydrogen producers at a disadvantage by disregarding the actual renewable content of the fuel and forcing them to look elsewhere for renewable

feedstocks. CARB should seek to create a fair market for LCFS credits by holding fuel producers to the same standards. CARB should also consider allowing renewable hydrogen project developers to leverage existing landfill gas production in California as an eligible feedstock to meet SB 1505 requirements and to qualify for LCFS credits at least in the near-term. California is phasing organic waste out of landfills and limiting new landfill gas projects but existing landfill gas projects have the potential to help bridge the gap in renewable hydrogen production while new facilities emerge using different feedstocks.

Ensuring that hydrogen has equal access to LCFS credits and that the program properly incentivizes the development of renewable hydrogen is critical to ensuring adequate private sector investment in infrastructure and innovation that can meet California's climate, clean energy and clean transportation goals. (EIN1_B11-4)

> **Agency Response:** The commenter refers to renewable hydrogen requirements set by California Senate Bill 1505 (Lowenthal).[6] As part of this rulemaking staff proposed to use LCFS reporting to monitor statewide progress toward achieving the objectives of the Statute and, therefore, staff's proposed requirements in the LCFS are designed to mirror the requirements of the Statute with respect to the determination of renewable content of hydrogen. The renewable content determination is not otherwise necessary under the LCFS methodology for evaluating the carbon intensity of fuels and issuing credits or deficits.
>
> SB 1505 specifically prohibits counting as renewable any electricity that is counted towards meeting the renewables portfolio standard (RPS) obligation, as required by Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code. Accordingly, the proposed LCFS regulation would require that any renewable electricity used to produce hydrogen must be above and beyond RPS requirements in order to be counted as renewable hydrogen.
>
> In contrast—and consistent with all transportation fuels under the LCFS—for the purpose of determining carbon intensity scores, emissions associated with renewable electricity that is counted towards meeting the RPS obligation are evaluated. Electricity that is used as an energy input in any fuel pathway under the LCFS is evaluated using the grid resource mix provided in U.S. EPA's eGRID database. Staff proposes an exception for California average grid electricity that is used as a transportation fuel, to use the grid resource mix data provided by California electricity producers to CEC, to enable more frequent (annual) updates.

[6] SB 1505 requires that hydrogen produced for, or dispensed by, fueling stations that receive state funds, and—following a 12-month period once the mass of hydrogen fuel dispensed for transportation purposes in California exceeds 3,500 metric tons—on a statewide basis, no less than 33.3 percent of the all hydrogen produced or dispensed in California for motor vehicles be made from eligible renewable energy resources as defined in subdivision (a) of Section 399.12 of the Public Utilities Code.

Finally, in contrast to the commenter's assertion, the LCFS places no limitation of the use of existing (or new) landfill gas in production of renewable hydrogen.

D-5.1b. Comment: And lastly, we want to flag that while renewable grid content contributes to LCFS credit values for plug-in electric vehicles, renewable hydrogen producers don't receive LCFS credits for the same electricity. This puts hydrogen producers at a disadvantage by disregarding the actual renewable content of the fuel, forcing them to look elsewhere for renewable fuel stocks.

CARB should seek to create a fair market for LCFS credits by holding fuel producers to the same standards and should consider allowing renewable hydrogen project developers to leverage existing landfill gas production in California as an eligible feedstock to meet SB 1505 requirements and to qualify for LCFS credits at least in the near term.

California's phasing organic waste out of landfills and limiting new landfill gas projects, but existing landfill gas projects have the potential to really help bridge the gap in renewable hydrogen production while new facilities emerge using different feedstocks. (EIN2_T30-6)

Agency response: The proposed amendments do include a smart electrolysis pathway and allow the use of book-and-claim accounting for renewable or low-CI electricity indirectly supplied to hydrogen production through electrolysis, which is consistent with the amendments allowing for smart charging and book-and-claim accounting for renewable or low-CI electricity indirectly supplied to electric vehicle charging. Staff also clarified that book-and-claim accounting could be used for renewable natural gas supplied as a feedstock for production of renewable hydrogen. Book-and-claim accounting allows renewable natural gas produced from existing landfills to be matched to the natural gas feedstock used to produce hydrogen using steam methane reforming.

D-6. *Electricity*

D-6.1. *Support for the Proposed Electricity Provisions*

D.6-1a. Multiple Comments: *Support for Proposed Amendments to the Electricity Provisions*

Comment: *Provide Stronger Signals and Increase Accessibility for Zero Emission Fuels*

The LCFS is a key component of California's transition to zero emission technologies and fuels, and the regulation should be strengthened to provide an even stronger push in this direction. Strengthening the overall target as recommended will help in this regard, but there are other parts of the regulation that can be strengthened to provide greater support to zero emission technologies and greater assistance in promoting ZEV markets. The proposal recognizes that the estimated carbon benefits of zero emission vehicle use need to be updated to ensure more accurate representation of the carbon benefits of zero emission technologies. We support the proposal to annually update estimates of the

California electrical grid to better reflect renewable power benefits, and to update the efficiency credits earned by zero emission trucks and buses to reflect the most recent research. We also support the proposal to credit transportation refrigeration units under the LCFS as an important signal that the freight sector must continue to innovate and transition to zero emission technologies as quickly as possible.

…

I support the efforts to update the evaluations of zero emission fuels and believe that these actions will ensure strong progress and health protections under the next generation of the LCFS. (VB1_10-3)

Comment: *Provide Stronger Signals and Increase Accessibility for Zero Emission Fuels*

The LCFS is a key component of California's transition to zero emission technologies and fuels, and the regulation should be strengthened to provide an even stronger push in this direction. Strengthening the overall target as recommended will help in this regard, but there are other parts of the regulation that can be strengthened to provide greater support to zero emission technologies and greater assistance in promoting ZEV markets. The proposal recognizes that the estimated carbon benefits of zero emission vehicle use need to be updated to ensure more accurate representation of the carbon benefits of zero emission technologies. We support the proposal to annually update estimates of the California electrical grid to better reflect renewable power benefits, and to update the efficiency credits earned by zero emission trucks and buses to reflect the most recent research. We also support the proposal to credit transportation refrigeration units under the LCFS as an important signal that the freight sector must continue to innovate and transition to zero emission technologies as quickly as possible.

…

We support the efforts to update the evaluations of zero emission fuels and believe that these actions will ensure strong progress and health protections under the next generation of the LCFS. (HMO1_113-3)

Comment: As a company that is deploying all-electric and plug-in hybrid vehicles in California, Jaguar Land Rover continues to support policies that promote the advancement of electrification in the State and globally.

The widespread availability of electricity as a transportation fuel means that EV customers can use residential, workplace, private, public or commercial charging solutions. We support the staff's stated goal to simplify EV charging reporting while providing opportunities for greater participation. (JLRNA1_44-1)

Comment: Additionally, the Joint POUs supports the methodology for calculating base credits for non-metered residential EV credits outlined in § 95486.1(c)(1). (JPOUS1_59-3a)

Comment: As discussed below, the Smart EV Charging Group supports the California Air Resources Board (ARB) staff's initiative and foresight in developing proposed LCFS amendment language that would encourage the expanded use of low carbon resources in electrifying the state's transportation networks. The Proposed Amendments would create a holistic approach to recognizing and incorporating community choice aggregators (CCAs) into the LCFS market and will mark an important step forward for LCFS policy development and integration of California policy initiatives.

…

The Smart EV Charging Group supports the general direction of the proposed amendments…

…

The Smart EV Charging Group generally supports the proposed amendments to the LCFS regulation because they would take an important step forward in enabling new incentive mechanisms for EV charging in California. (SEVCG1_116-1, SEVCG2_B10-1)

Comment: III. Simplify processes to encourage increased electricity use. We support the regulatory approach to generate credits from electricity as a transportation fuel... (PGE1_120-6a)

Comment: Starting off, thank you to Sam and the staff for proposing enhancements to promote expansion of electric vehicle infrastructure and other kind of proposals around the electricity as a fuel.

In particular, we think it will help support the Governor's Executive Order B-48-18, which has several benchmarks, and we think this will help assist with that, the proposals as well. (CHARGEPOINT2_T8-1)

Comment: And lastly, we support broadening opportunities within residential electric vehicle charging… (CHARGEPOINT2_T8-4)

Comment: Specifically the health community letter focused on the role of the LCFS in spurring more zero-emission vehicles and fuels necessary to meet our clean air and climate goals. We supported the annual grid updates for California electricity; increasing the energy efficiency ratio for trucks and buses, to boost that signal, as ARB considers many rulemakings going forward to expand those markets for zero-emission trucks and buses. (HMO2_T15-3)

Comment: Now, I want to turn to electricity As said earlier by CalETC and Tesla and others, the utilities are currently using the LCF revenues to support the market through rebates and charging infrastructure. This is great. This is a good thing, and we like it, but we think there is substantial room for improvement in the way that this is working today. (GM1_T49-2)

Agency Response: Staff appreciates the commenters' support for the proposed amendments to the provisions for reporting electricity as a transportation fuel. Staff believes these changes would further promote use of electricity as a low carbon transportation fuel.

D-6.1b. *Support for Zero-CI Electricity Lookup Table Pathway*

Comment: BART appreciates that CARB's draft LCFS Regulation would recognize procurement of clean electricity from solar or wind generation sources. Proposed Section 95488.5, Table 7-1 of the draft LCFS Regulation includes a new lookup table pathway ELCR, which assigns "[e]lectricity that is generated from 100 percent solar or wind supplied to electric vehicles in California" a carbon intensity value of zero. (BART1_12-1a)

Agency Response: Staff appreciates the commenter's support for the addition of a zero-CI pathway to the Lookup Table and notes that the pathway was modified in a 15-day change to include additional electricity resources that can be reported under this Lookup Table pathway.

D-6.1c. Multiple Comments: *Support for the Proposed Updates to EER Values for Light-Duty Electric Vehicles and Heavy-Duty Electric Buses and Trucks*

Comment: Proterra, the leading U.S. manufacturer of zero-emission, battery electric transit buses, strongly supports the proposed increase in Energy Economy Ratio (EER) for heavy-duty battery electric buses from 4.2 to 5.0. Zero-emission battery electric bus technology continues to improve, and when compared to conventional gasoline and diesel fuel vehicles, zero-emission buses are increasingly more efficient and competitive in miles per gasoline gallon equivalent. The proposed EER reflects these advances in heavy-duty technologies, and will help ARB carry out its goal of reducing the carbon intensity of fuels and encouraging the use of lower-carbon alternatives in California. (PROTERRA1_46-2)

Comment: We also support CARB's effort to revise the Energy Efficiency Ratio for battery electric trucks and buses to better reflect real world efficiency gains over combustion technologies. (UCS1_53-5a)

Comment: 4. <u>Efficiency of Electric Trucks:</u> approve staff's proposal to update the Energy Economy Ratio (EER) for heavy-duty EVs.

…

IV. Approve staff's proposal to update the EER for heavy-duty EVs.

Tesla supports CARB's proposal to increase the EER for heavy-duty EVs from 2.7 to 5.0 based on CARB's analysis of "Battery Electric Truck and Bus Energy Efficiency Compared to Conventional Diesel Vehicles".[9] This adjustment reflects the dramatically

higher efficiency of the electric powertrain versus conventional combustion engine technology.

[9] https://www.arb.ca.gov/msprog/actruck/docs/HDBEVefficiency.pdf

As EERs are often a comparison of miles per gasoline gallon equivalent (MPGe), we encourage CARB to revisit the appropriateness of the EER for light-duty EVs in the next rulemaking using this methodology. The 2015 average U.S. light duty vehicle fuel efficiency was 22.0 miles per gallon of gasoline.[10] For currently available EVs (including the Tesla Model S, X and 3 and the Chevy Bolt, among others), the average miles per gallon equivalent is 103.5. Therefore, given an equivalent amount of energy, an EV travels approximately 4.7 times further than an ICE vehicle. This difference should be reflected in the EER for light-duty EVs, which is currently set at only 3.4.

[10] Average Fuel Efficiency of U.S. Light Duty Vehicles. Bureau of Transportation Statistics (2015). https://www.bts.gov/content/average-fuel-efficiency-us-light-duty-vehicles

…

Based on the foregoing, we believe CARB should … iv) increase the heavy-duty EER to reflect the efficiency of EV powertrains… (TESLA1_79-5)

Comment: *SMUD supports the updated and new EER values in Table 5 for vehicles and other equipment using electricity as a primary fuel.* SMUD would like to commend staff for the test data collection and analysis to establish all the new EER values for such a wide array of applications as shown in Appendix H. (SMUD1_85-8)

Comment: In addition to that, we support the proposal to update the energy/economy ratio to basically better reflect the efficiency of an electric powertrain versus a combustion engine powertrain. So we think that change should be made. (TESLA2_T26-3)

Comment: 4. CalETC supports the draft regulation order's proposal for … changes to the energy economy ratio (EER) which will provide justifiably larger LCFS credits to most types of electric transportation:

a. CalETC supports keeping the light-duty EV EER at 3.4 and increasing the heavy duty EV and electric bus EER to 5.0;

…

4. *CalETC supports the draft regulation order's proposal for … changes to the energy economy ratio (EER) which will provide justifiably larger LCFS credits to most types of electric transportation*

a. *CalETC supports keeping the light-duty EV EER at 3.4 and increasing the heavy duty EV and electric bus EER to 5.0*

…

The draft regulation order proposes to change the EER for electric buses and electric medium-duty and heavy-duty vehicles to 5.0 and provides justification in Appendix H.[4] CalETC also believes the staff report has appropriately and conservatively justified the proposed changes to EERs. CalETC also believes it is important to keep the EERs as simple[5] as possible to make it feasible for fleets that charge many different sizes of EVs.

[4] Appendix H of the formal regulatory documents available on the CARB website.

[5] Having one EER for light duty and another for medium and heavy duty EVs should be workable.

(CALETC1_96-6b)

Agency Response: Staff appreciates the commenters' support for the proposed amendments to update the Energy Economy Ratio (EER) for light-duty electric vehicles and heavy-duty electric buses and trucks.

D-6.1d. *Support for EER value for Electric Forklifts*

Comment: DANNAR strongly supports the proposed Energy Economy Ratio (EER) for electric forklifts of 3.8. Our company also strongly supports the proposed inclusion of other mobile freight and goods movement equipment as eligible technologies. Zero-emission battery electric off-road technology, including forklifts, are commercially available and can help phase out old, diesel equipment for cleaner, low-carbon alternatives. This will help continues transition of California's freight and goods movement sector towards electrification, and help carry out the objectives of the Sustainable Freight Action Plan as well as the Low Carbon Fuel Standard. (DANNAR1_7-2)

Agency Response: Staff appreciates the commenter's support for the proposed amendments. Staff would like to highlight electric forklifts are eligible to generate credits under the current LCFS regulation as well.

D-6.1e. *Support for the Proposed EER Value for Electric Transportation Refrigeration Units*

Comment: AEM agrees with the EER value proposed in the amended regulation of 3.4 as an appropriate value to establish eTRU as a new category in the LCFS. This value is appropriate for electric standby transport refrigeration where electric standby represents the majority of eTRU in the market today. Electric standby has been commercially available for over 15 years yet is not widely adopted.[1] The inclusion of eTRU in the LCFS can incentivize and expand the use of electric transport refrigeration in support of the California Sustainable Freight Action.

[1] *Market and Technology Assessment of Electric Transport Refrigeration Units*. EPRI , Palo Alto, CA: 2015. 3002006036

(AEM1_54-3)

Agency Response: Staff appreciates commenter's support for the proposed EER value for electric Transportation Refrigeration Units (eTRUs).

D-6.1f. Multiple Comments: ***Support for the Proposed Addition of New Transportation Applications***

Comment: The Joint POUs support the proposed regulation order inclusion of new categories of transportation electrification: mobile freight and goods movement equipment,[7] electric truck refrigeration units,[8] and on-road electric motorcycles.[9] In addition to these specific categories, the Joint POUs support allowing any technology that replaces gasoline or diesel with electricity to generate LCFS credits, and encourage CARB to conduct at least one public workshop to explore a broader technology expansion.

7 § 95843(c)(4)
8 § 95843(c)(5)
9 Table 5 in § 95486.1(a)

(JPOUS1_59-6)

Comment: AEM supports the proposed amendment to include electric transport refrigeration units (eTRU). With our pleasure we submit these comments:

<u>Electric Transport Refrigeration Units:</u>

AEM applauds the inclusion of electric transport refrigeration units (eTRU) in the proposed amended regulation. We are pleased to see eTRU technology recognized for displacement of diesel fuel with the substitution of electricity as a clean, low-carbon way to deliver fresh, frozen, or perishable food. (AEM1_54-2)

Comment: 7. CalETC supports the draft regulation order's proposal for several types of electric transportation to be able earn credits (other mobile freight electric equipment, electric truck refrigeration units and electric motorcycles), and requests a new process for quickly allowing new categories of electric non-road equipment and marine vessels to generate credits.

…

7. CalETC supports the draft regulation order's proposal for several types of electric transportation to be able earn credits (other mobile freight electric equipment, electric truck refrigeration units and electric motorcycles), and requests a new process for quickly allowing new categories of electric non-road equipment and marine vessels to generate credits.

The current regulation order appropriately seeks to address a fairness issue. In the current LCFS, electricity is not eligible to earn credits for many types of vehicles and non-road transportation equipment when other low-carbon fuels are eligible to generate credits for these technologies. The draft regulation order would allow electric motorcycles, electric transport refrigeration units and other electric mobile freight equipment to earn LCFS credits. CalETC supports these changes and believes LCFS credits should be generated for any technology that replaces gasoline or diesel with electricity.

CalETC recommends that the 15-day change period include amendments to the LCFS establishing EERs for additional electric non-road equipment and marine vessels, thereby allowing these vehicles to earn the accurate LCFS credit value. In addition, for categories of equipment where EERs are less certain, CalETC requests the 15-day comment period establish conservative, default or temporary EERs for non-road equipment and marine vessel applications. These modifications would place transportation electrification technologies on a fair playing field with other clean fuel transportation technologies.

CalETC recommends a process be established for "EER pathway applications" similar to a Tier 1 pathway, or process similar to Table 7-2 where the numbers are updated by CARB staff on a frequent basis and subject to public comment. This would allow CARB staff to be able to continually use the best data from national labs, universities, research institutes and the private sector to create EERs for the wide variety of electric equipment used for transportation in diverse sectors such as agriculture, mining, airports, factories, education, marine and port terminals. (CALETC1_96-10)

Comment: CAPA supports the California Air Resources Board's (CARB) consideration of funding additional incentive programs through the Low Carbon Fuel Standard (LCFS) by incorporating additional categories of Energy Economy Ratios (EERs). Incentivizing the Ships At-Berth Program, which requires vessels to turn off their onboard auxiliary engines and plug into the electric grid for power while docked, as well as Cargo Handling Equipment (CHE) clean fueling options, provides an ample opportunity to further lower emissions at California's seaports. (CAPA1_109-1)

Comment: Opening up the LCFS for consideration of CHE and At-Berth incentives provides additional opportunity to improve the air quality at our facilities and the neighboring disadvantaged communities. (CAPA1_109-2)

Comment: #2. We support the addition of new types of electric vehicles.

We support the proposal to allow additional types of electric transportation to be eligible for LCFS credits, and we encourage CARB to adopt a new process for quickly allowing new categories of electric non-road vehicles to do so as well. We believe this category should potentially include electric aircraft, which have recently debuted in California and could reach several thousand in number by the early 2020s. (CALSTART1_B6-3)

Comment: We support the TRU provisions to send again a clear and strong signal that the freight sector has to clean up its emissions and move to electrification. (HMO2_T15-4)

> **Agency Response:** Staff appreciates the commenters' support for the proposed amendments to allow electric Transport Refrigeration Units (eTRU), electric Cargo Handling Equipments (eCHE), and electric shore power supplied to Ocean-going Vessels at-berth (eOGV) to be eligible for reporting and generating credits in LCFS. This includes Energy Economy Ratios (EER) for the new

electric transportation applications as proposed by the staff to facilitate LCFS reporting.

In response to comments JPOUS1_59-6, CALETC1_96-10, and CALSTART1_B6-3, staff agrees that as new and innovative electric transportation technology emerges, specific EER values would be required to facilitate accurate reporting in the LCFS program. Previously new EER values could only be added through the rulemaking process, which limited the program's ability to timely recognize new and innovative technologies using low-carbon fuels. Therefore, as part of these amendments, staff propose that, in cases when appropriate EER is not available, applicants can apply for an EER-adjusted carbon intensity score through the existing Tier 2 fuel pathway application process to accommodate their unique vehicle-fuel combination. The methodology used for calculating EER-adjusted CI must compare useful output from the alternative fuel technology to that of comparable conventional fuel technology. Once an EER-adjusted CI is certified then it would be available to the applicant for reporting purposes. This is an appropriate extension to the fuel pathway life cycle analysis process that is necessary to correctly capture fuels that facilitate significant vehicle efficiency benefits.

D-6.1g. Multiple Comments: *Support for the Incremental Credit Provisions*

Comment: Further expanding the opportunity for entities, particularly beyond the electric distribution utilities (EDUs) for residential EV charging, to generate and administer LCFS credits for transportation electrification has enormous potential to reduce emissions associated with the transportation sector. The proposed approach of enabling the generation of LCFS credits reflecting the incremental impact of lower carbon intensity (CI) electricity supply and time of use is reasonable and a good foundation for creating an LCFS that more accurately reflects the differential between the statewide grid average and electricity actually supplied.

…

I. Adopt the proposed approach of allowing the generation of "incremental credits" reflecting improvements (over the California Average Grid Electricity Pathway) in carbon intensity of electricity. We support the inclusion of multiple methods for accounting for renewable electricity charging in this rulemaking cycle. We commend the ARB for broadening opportunities for credit generation with residential EV charging. (SEVCG1_116-2, SEVCG2_B10-2)

Comment: We support Staff's recommendation to allocate incremental credits for residential EV charging based on the carbon intensity of load-serving entities. (CHARGEPOINT1_122-7a)

Comment: In particular, we're supportive of the provisions that would allow for incremental credit generation, particularly for community choice aggregators that can

demonstrate that the generation that they're providing to their EV customers has a lower carbon intensity than what they might otherwise get from the grid.

One of the things that I think that these amendments will allow companies like CCA's to do is to offer innovative programs. You've heard a lot today about the need to move beyond after-the-fact rebates, which is how residential customers currently benefit from the LCFS program, and really move to more of a point-of-sale-based rebate.

In Sonoma County, the Sonoma County Clean Power Authority did just that. They without any LCFS credits offer point-of-sale rebates. And we saw in the one year that we did this -- the previous year, you know, there was about a hundred sales of EVs. It went up to about 711 EVs in the one year that that program was launched. They also installed 1700 chargers, and they're actively working with the transportation agency to electrify the transportation that work in the county.

So opening up the LCFS credit market to these kinds of innovative programs really will allow much greater EV adoption, greater electrification of our transportation networks. So we strongly support the amendments for those reasons. (SCPA1_T28-2)

> **Agency Response:** Staff appreciates the commenters' support for the incremental credit provisions and would like to clarify that incremental credits can be generated only for improvements in the average grid electricity carbon intensity used for residential EV charging by providing low-CI electricity or for smart charging pursuant to section 95483(c)(1)(B).

D-6.1h. *Support for the Proposed Amendments to the Electric Forklift Provisions*

Comment: 3. CalETC supports the draft regulation order's proposal for electric forklifts.

…

3. *CalETC supports the draft regulation order's proposal for electric forklifts.*

The draft regulation order proposes several changes to the current LCFS for electric forklifts, including allowing forklift fleet owners to contractually designate the credit generating responsibilities to third parties. These credits would be subtracted from the estimated credits that CARB staff provides to EDUs. The draft regulation order also improves the formula for forklift LCFS credit generation.[1]

[1] See page 77 in the draft regulation order or § 95486.1 a) 4) which would allow hydrogen and electric forklifts introduced after 2010 to earn LCFS credits similar to new fixed guideway systems that were introduced after 2010.

(CALETC1_96-5)

> **Agency Response:** Staff appreciates the commenter's support for the proposed changes to the electric forklift provisions.

D-6.1i. Multiple Comments: *Support and Recommendations for the Proposed Smart Charging and Smart Electrolysis Pathways*

Comment: *NextGen Supports the Adoption of Time-of-Use Charging ("Smart Charging") Credits*

LCFS program staff have proposed adding a Time-of-Use EV charging, or "Smart Charging," bonus credit. This would be applied in addition to the normal baseline credits for charging an EV. Charging activity that occurred between 9:00am and 4:00pm would be eligible for a credit of an amount which reflects the expected emissions savings from using curtailed solar energy rather than the normal marginal grid mix. The estimated emissions savings would vary on a quarterly basis and be regularly updated to reflect current grid conditions.

NextGen California strongly supports the inclusion of Smart Charging credits, per Staff's proposal. Significant amounts of solar energy are regularly curtailed between 9:00am and 4:00pm, encouraging vehicle charging during that time can make use of this otherwise wasted resource. This credit particularly supports broad deployment of workplace charging infrastructure, which is a critical need in California.

We suggest Staff consider whether the Smart Charging credit could be expanded to provide a dis-incentive for charging during times of peak grid demand, such as 5:00pm to 9:00pm, however we recognize that dis-incentive provisions are more complicated than incentives, and so may take more time and effort to design. We also encourage CARB to move as quickly as is feasible towards routinely using real-time telematic or charger data to base incentives around actual grid conditions, rather than seasonal estimates. (NEXTGEN1_124-37)

Comment: 12. CalETC supports, in concept, the draft regulation order's proposal for incremental time-of-use (TOU) credits for electricity based on periods of curtailment of renewable power, but suggests this provision be reviewed as data is collected to best ensure accurate carbon intensity valuation.
…

12. *CalETC supports, in concept, the draft regulation order's proposal for incremental time-of-use (TOU) credits for electricity based on periods of curtailment of renewable power, but suggests this provision be reviewed as data is collected to best ensure accurate carbon intensity valuation.*

The draft regulation proposes an option to recognize and reward the GHG benefits of shifting EV charging to times when intermittent renewable electricity might otherwise be curtailed.[16] These LCFS credits would be for incremental reductions above and beyond the 72 to 81 percent reductions associated with grid-electricity, and could be combined with low-CI electricity incremental LCFS credits. CalETC supports this option; it will aid in the integration of renewable energy onto the grid and in management of EV load. However, we recommend that CARB staff, during the quarterly process to update Table 7-2 consider additional data sources and ensure these curtailment credits are supporting utilization of renewable resources in transportation electrification.

[16] 95488.5(f) Time-of-Use Lookup Table Pathways

CalETC requests a 15-day change to include a review of the incremental TOU credits including examining additional data sources, TOU schemes (e.g., ISO curtailment periods or CPUC's TOU periods), adoption of TOU incremental credits, and customer acceptance. The 15-day change would also include continuing regular reviews during implementation as more data is generated. These reviews will improve both the accuracy and simplicity of curtailment credits. In general, while supportive, CalETC is concerned about the complexity of this new provision in the draft regulation order. (CALETC1_96-15)

Comment: CARB staff is recommending addition LCFS credits for charging during curtailment periods. CalETC supports this recommendation but recognizes that the implementation is complicated and is recommending regular review and reconsideration based on data collected. (CALETC2_130-4)

Comment: In *§95488.5(f) Time-of-Use Lookup Table Pathways*, CARB proposed an option to recognize and reward "the GHG benefits of shifting EV charging and electrolytic hydrogen load to the periods of time when intermittent renewable electricity might otherwise be wasted (curtailed)." PG&E supports this option and concurs that it could produce incremental credits while aiding renewable energy integration and managing EV load, particularly for non-residential entities. However, we recommend that CARB address two important issues to prevent EV charging and electrolytic hydrogen load being shifted to times when their impact on GHGs is worse than if a California grid-average value were used (i.e., if no TOU table were used): a) TOU pathway CIs should accurately reflect actual curtailment and marginal heat rates, and b) TOU Carbon Intensities should align with EV Charging Rates.

a) TOU pathway CIs should accurately reflect actual curtailment and marginal heat rates: CARB notes in *§95488.5(d)(2) Update to Time-of-Use Electricity Pathways* that, "In order to reflect the seasonal variation of electricity generating resources in California and to maintain accounting consistency with the CI of the California Average Grid Electricity pathway, the Executive Officer will use the methodology described in the supporting document specified in section 95488.5(e) and the public comment process described in 95488.5(d)(2) to update the time-of-use pathway CIs in Table 7-2."

CARB then provides the TOU pathway CIs in *§95488.5(f) Time-of-Use Lookup Table Pathways*, and notes that for the California grid electricity that may be used for reporting EV charging and hydrogen produced via electrolysis, the Executive Officer will calculate TOU carbon intensities each quarter and provide them on the LCFS web site.

PG&E is concerned that the TOU pathway CIs does not accurately reflect curtailment and marginal heat rates, and therefore mischaracterize the CI of electricity at certain periods in the table. Specifically, the simplified curtailment data source used[8] does not distinguish between periods of *local curtailment* (during which EV charging and electrolytic hydrogen load outside the local curtailment pocket result in increased GHG emissions) and periods of *system curtailment* (during which EV charging and electrolytic hydrogen load result in zero marginal GHG emissions). The curtailment data used in these calculations therefore over-estimates the impact of curtailment on marginal GHG

emissions, and under-estimates the marginal emissions during the middle of the day (when local curtailment is most prevalent).

[8] http://www.caiso.com/Documents/HistoricalProduction-CurtailmentDataNowPosted-ISOWebsite.html

At the same time, the TOU pathway CIs do not accurately reflect the differences between marginal heat rates of thermal generation (and therefore the CI of electricity) at different times of the day and different seasons. For example, during the middle of the day (9 AM-3 PM) and the middle of the night (midnight-6 AM), efficient combined cycle generators are typically running, so the CI of electricity should be low even when renewables are not being curtailed. In contrast, during the late afternoon and evening (4 PM-9 PM), less efficient 'peaker plants' may be running, so the CI of electricity should be higher then. This is in alignment with current or proposed TOU rates for all three investor-owned utilities (IOUs), which have a peak period between 4 and 9 PM based primarily on marginal generation costs, which are driven by these same heat rate factors. The TOU pathway CIs actually have a *higher* CI between midnight and 6 AM than between 4 PM and 9 PM, and if implemented would incent EV charging when GHG emissions are high and the grid is more stressed.

We recommend that CARB consider adopting the methodology for calculating marginal GHG emissions described in the 2016 Itron/E3 SGIP Evaluation Study[9] to calculate the marginal emissions impact of EV charging and electrolytic hydrogen production. This methodology was used in all three IOUs 2018 Rate Design Window (RDW) applications to model the impact of default rates on GHG emissions[10] and is also being used by the GHG Signal Working Group that was established by CPUC Ruling 12-11-005[11]. The calculation of marginal GHG emissions is expected to be updated once a quarter as part of the process pursuant to this Working Group, which could support CARB's quarterly updates to the TOU Pathway CIs.

[9] http://www.cpuc.ca.gov/General.aspx?id=7890

[10] The impact of default rates on GHGs was modeled using day-ahead rather than real-time heat rates, due to the long-term nature of customer load shifts. PG&E's 2018 Rate Design Window application- http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M212/K893/212893197.PDF

[11] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M202/K276/202276301.PDF

b) TOU Carbon Intensities should align with EV Charging Rates: PG&E is concerned that the TOU pathway CIs listed in Table 7-2 do not align with the TOU periods established in the IOUs EV charging rates (e.g., the peak CI in the table is in the early morning when the TOU customer rates are the lowest). To support consistency between the times with the lowest CIs and the times with the lowest rates, we suggest that CARB compare the TOU pathway CIs with the utilities' EV rates whenever the CIs are updated (i.e., quarterly). (PGE1_120-21)

> **Agency Response:** Staff appreciates the commenters' support for the proposed smart charging provisions to incentivize shifting EV charging to times when marginal emission rate of grid electricity would be lower than the average emission rate. Staff believes this proposal would promote the use of low-CI electricity as a transportation fuel and could deliver greater grid benefits by reducing curtailment of excess renewable energy.

Staff appreciates the recommendations provided in the comments to use marginal GHG emission signal for calculating hourly CI values for smart charging pathway. In the initial proposal, posted on March 6, 2018, staff proposed a methodology to calculate CI values for smart charging and smart electrolysis pathways based on the historical probability of renewable resources curtailment in California. The intent of the original proposal was to deliver greater emission reductions and grid benefits by incentivizing to shift EV charging or electrolytic hydrogen load to times when marginal emission rate of grid electricity would be lower than the average emission rate. However, stakeholder comments expressed that calculating these credits using grid's marginal greenhouse gas emissions would be a better approach. Staff agrees with the commenter's recommendation, and in response to these comments, staff modified the methodology to use marginal GHG emission signals from the California Public Utilities Commission's (CPUC) Avoided Cost Calculator (ACC) instead of using curtailment probability to determine the hourly CI values for smart charging or smart electrolysis pathways. Given that the ACC provides estimates of marginal emission rates for future years, staff proposed to provide the hourly smart charging CI's at the start of the year for each quarter. Staff proposed to update the smart charging CI table annually.

Staff also proposed that to be eligible for smart charging pathway a residence must be enrolled in an EV specific time-variant rate plan, if offered by the Load Serving Entity (LSE). The entity using smart charging pathway for reporting electricity must be able to provide records for the enrollment in the EV specific time-variant rate, upon request by the Executive Officer. If the LSE does not offer an EV specific time-variant rate plan then the reporting entity must provide documentation demonstrating that fact. This change would ensure the smart charging pathway aligns with utility offered time-variant rates to provide a consistent signal about when EV charging should be occurring to deliver maximum grid benefits.

Staff is committed to working with stakeholders to update or modify the smart charging and smart electrolysis pathways to further promote use of low-CI electricity as transportation fuel.

D-6.1j. Multiple Comments: ***Support LCFS for Promoting ZEV Adoption and Transportation Electrification in California***

Comment: These changes could be implemented immediately upon conclusion of the rulemaking process, and the value generated from the sale of credits would directly benefit California consumers, accelerate the adoption of zero emission vehicles and increase renewable energy generation. (TESLA1_79-7)

Comment: The electricity pathway within the LCFS is an important tool to support the Governor's goals of placing more than 1.5 million Electric Vehicles (EVs) on California roads by 2025 and 5 million by 2030. (CVAQ1_43-1)

Comment: A well-structured LCFS will ensure that LCFS credit value reduces the cost of owning electric vehicles and speeds the transition to electric drive across the entire transportation sector. However, key implementation details are very important to realizing the full potential for synergy between the LCFS and statewide electrification goals. (UCS1_53-4a)

Comment: Substantial challenges must be overcome before this future can be realized. Customer attitudes toward EVs must shift. We believe that programs such as the LCFS provide needed incentive to move customers toward adoption.

Allowing multiple pathways and business models to participate in the LCFS charging credit generation process can maximize the incentives for electric vehicle owners, leading to increases in the electric vehicle fleet across California roads as well as electric vehicle miles traveled. (FORD1_58-2)

Comment: In addition to an upfront incentive, SMUD believes that LCFS credit revenue earned through residential base credits also has benefits in developing and incenting charging infrastructure to support the Governor's goal of 5 million zero-emission vehicles (ZEV) by 2025. (EO B-48-18) Currently, the California Energy Commission (CEC) forecasts between 1.5 million and 2.4 million ZEVs will be on California roads by 2025. However, the CEC also forecasts that up to 175,000 public charging stations will be needed to support just 1.5 million ZEVs, which is far below the 5 million ZEV goal. Thus, there is a critical need for more charging infrastructure. The EDUs are in a unique position to assess where charging infrastructure should be located and to provide public access to it. We believe this is especially important to help grow the used EV market and also provide charging options in disadvantaged communities that lack provisions for vehicle charging. (SMUD1_85-4)

Comment: The electricity pathway within the LCFS is an important tool to support the Governor's goals of placing more than 1.5 million Electric Vehicles (EVs) on California roads by 2025 and 5 million by 2030. As an organization supporting the deployment of renewable energy (solar) technology in the state, we are well-positioned to help advance the objectives of the LCFS program in reducing the carbon intensity of the state's transportation fuels. We provide these comments for CARB's consideration to help the LCFS program drive growth of zero-emission transportation in California. (SEIA1_119-1)

Comment: #3. We encourage continuous improvement towards making LCFS credits work to stimulate new ZEV sales.

Over the past year, staff has begun to consider ways that the disbursement of LCFS credits, which in the case of residential EV owners occur largely after the point of sale, could more effectively serve as a catalyst for purchases. We agree with this direction because we favor bringing the value of the LCFS up to the point of sale so that it can work as a point-of-purchase incentive.

We realize that there are different ways to do this, and the considerations involved are technical and substantial. We also acknowledge that current discussions are under way on this matter between several parties including utilities and automakers. We encourage that staff continue to explore options in this area. (CALSTART1_B6-4)

> **Agency Response:** Staff appreciates the commenters' support for the LCFS electricity provisions in general and for the specific proposed LCFS amendments to support Zero Emission Vehicle (ZEV) adoption and promote use of electricity as a low carbon transportation fuel described in the comments above. Staff agrees that the LCFS is an important tool to support the Governor's goals of placing more than 1.5 million Electric Vehicles (EVs) on California roads by 2025 and 5 million by 2030 and to help in developing the charging infrastructure necessary to support these EVs. Staff also agrees that EDUs are well positioned to identify where charging infrastructure should be located and to provide public access to it, especially in disadvantaged communities.

D-6.1k. Multiple Comments: ***Support Electric Distribution Utilities (EDU) as Base Credit Generator for Residential EV Charging***

Comment: With regards to the draft proposed regulation order, the Joint POUs support continuing to allow electric distribution utilities ("EDUs") to earn LCFS credits for residential charging estimated by CARB staff (estimated base residential credits) and updating the EDU carbon intensity values.

…

At the most fundamental level, the LCFS is a fuels regulation and as such credits should be generated by the primary fuel provider. In the case of electricity as a transportation fuel, the EDU is the primary fuel provider, investing significant resources in not only increasingly lower-carbon generation resources, but also the transmission and distribution system necessary to deliver the fuel to EVs. As a basic principle, LCFS credits generated from electricity should be provided to the EDUs on behalf of their customers, who are responsible for funding the grid infrastructure necessary to support transportation electrification.

…

The revised § 95843 of the proposed regulation order updates the provisions for electricity used as a transportation fuel. Residential EV charging is bifurcated into two credit categories: base credits and incremental credits. The Joint POUs support the proposed regulation order provision that electric distribution utilities ("EDUs") as the only entity eligible to generate base credits.[1] Additionally, the Joint POUs supports the methodology for calculating base credits for non-metered residential EV credits outlined in § 95486.1(c)(1).

[1] § 95843(c)(1)(A)

(JPOUS1_59-2)

Comment: *SMUD supports continuation of the Electricity Distribution Utility (EDU) as the credit generator for the base electric vehicle (EV) charging credits.* … SMUD supports the amendments proposed by staff to enable EDUs to continue to earn LCFS credits for residential charging estimated by staff (residential base credits). SMUD believes that this is best methodology to provide the LCFS credit value back to the EV drivers in a manner that helps increase EV adoption in the most equitable form, and provides the flexibility to meet local market needs and address multiple adoption barriers.

SMUD currently returns the residential base EV electricity credit value back to the customers through: 1) a one-time upfront cash incentive to charge free for two years ($599) or a free 240-volt Level Two EVSE unit; 2) investing in the expansion of public charging infrastructure in our service territory; 3) a consumer-forward advertising and outreach program aimed at raising knowledge of and interest in electric vehicles among our customers; and 4) innovative programs to incent workplace charging, fast-charging infrastructure, and electric transportation in disadvantaged communities. SMUD's one-time upfront cash/value incentive, advertised as "Free fuel for two years", is available to all our customers irrespective of what make and models of EV's and plug-in electric vehicles (PHEV's) they are purchasing. Data from our program indicates that approximately 73% of our customers purchasing or leasing PHEVs are participating in our incentive program. We feel that this provides the best equity for our community and provides program consistency since every customer in SMUD's service territory can participate in the program and no specific make or model of electric vehicle is favored. (SMUD1_85-2)

Comment: SDG&E strongly advocates to maintain the current LCFS regulation that allows an Electrical Distribution Utility ("EDU") to generate "base" LCFS credits for residential charging. Currently, SDG&E has a California Public Utilities Commission (CPUC) approved program that returns the revenues generated from the sale of LCFS credits to electric vehicle drivers residing in its service territory. SDG&E is committed to working with all stakeholders and regulators to create new pathways and reallocate the proceeds of LCFS credit sales to programs and investments that accelerate electric vehicle adoption, and meet California's transportation electrification goals. Moreover, the CPUC's governance over SDG&E's investments and programs creates an additional layer of checks and balances to ensure fair and equitable distribution of LCFS revenue to benefit all Californians. (SDGE1_91-2)

Comment: CalETC also supports the current program design with utilities generating "base" LCFS credits for residential charging and returning the value of those credits to electric vehicle drivers. CalETC and the utilities are committed to working with stakeholders and regulators to improve utility investment of LCFS credit value, so that this investment effectively accelerates the market for electric vehicles and supports the Administration and Legislature in meeting the state's transportation electrification goals. The utilities are uniquely positioned to work with the state to invest the LCFS credit value as they are either local public entities (publicly-owned utilities), or they are economically regulated (investor-owned utilities).

…

1. CalETC supports the allocation of base residential charging LCFS credits to electric distribution utilities (EDUs), and the requirements upon EDUs to return the LCFS credit value back to electric vehicle drivers.

…

1. *CalETC supports the allocation of base residential charging LCFS credits to electric distribution utilities (EDUs), and the requirements upon EDUS to return the LCFS credit value back to electric vehicle drivers.*

CalETC supports the current program design with utilities generating "base" LCFS credits for residential charging and returning the value of those credits to electric vehicle drivers. CalETC and the utilities are committed to working with stakeholders and regulators to improve utility investment of LCFS credit value, so that this investment effectively accelerates the market for electric vehicles and supports the Administration and Legislature in meeting the state's transportation electrification goals. The utilities are uniquely positioned to work with the state to invest the LCFS credit value as they are either local public entities (publicly-owned utilities), or they are economically regulated (investor-owned utilities). (CALETC1_96-2)

Comment: SCE supports the draft regulation's proposal that utilities continue to generate LCFS credits for residential charging, based on an improved carbon intensity factor for the statewide average grid. SCE has begun working with CARB on how to improve the utilities' programs that return the LCFS credit sale proceeds back to EV owners and improve consistency of the LCFS programs across the state. As you may know, for SCE, it is a $450 rebate mailed to customers for up to three different owners of the same EV over time,[2] and we hope that any improvements will continue to facilitate used-car EV ownership. We believe that the utilities are uniquely positioned to work with the regulators and stakeholders to determine how to best invest the utilities' LCFS proceeds in order to accelerate transportation electrification and benefit EV owners.

[2] Additional program features protect against fraud.

(SCE1_108-2)

Agency Response: Staff appreciates the commenters' support for keeping Electric Distribution Utilities (EDU) as the credit generator for base credits for residential EV charging. The LCFS is a fuels program incentivizing fuel providers supplying alternative transportation fuels to support reduction in carbon intensity of California's transportation fuel pool. EDUs play a critical role and make significant investments in the low-CI electricity generation resources and in the transmission and distribution networks essential for delivering fuel for EV charging, making them primary fuel providers for residential EV charging. EDUs are well positioned to promote the use of electricity as a low carbon transportation fuel by providing better rate options for residential EV charging, adapting and upgrading California's electric grid, and helping support

development of EV charging infrastructure. Therefore, staff proposed to keep EDUs as the credit generator for base credits for residential EV charging.

Staff is also supportive of the process set up between utilities and automakers to work together to determine the best utilization of LCFS credit value for residential EV charging, including the development of a statewide point-of-purchase rebate program for EVs. As part of the 15-day modifications to the proposed amendments, staff proposed revisions to accommodate such a program, should it be developed.

D-6.1l. Multiple Comments: Support for the Proposed Indirect Accounting of Renewable and Low-CI Electricity

Comment: In addition to the creation of a statewide point-of-sale EV incentive, we recommend that CARB proceed with allowing credit generators to match actual EV charging data with renewable energy generation to generate credits using a zero Carbon Intensity value. This will boost credit generation, increasing incentive values for consumers and supporting continued deployment of renewable energy in California. (BDP1_1-2, CULTURA1_15-2, CVAQ1_43-3, CCA1_52-5, WM1_83-2, ARIA1_98-3)

Comment: We support the current proposal to allow credit generators, such as EV manufacturers and charging station providers, within the electricity pathway to match actual EV charging data with renewable solar energy generation to generate credits using a zero Carbon Intensity value. This will boost credit generation, increasing incentive values for consumers and supporting continued deployment of renewable energy in California. (SEIA1_119-2)

Comment: Borrego supports the proposal to allow LCFS credit generators within the electricity pathway, such as electric vehicle (EV) manufacturers and EV charging station providers, to match EV charging data with solar energy generation to generate LCFS credits with a zero Carbon Intensity (CI) value. This will increase the ability of distributed solar energy to support the deployment of electrified transportation in California. (BORREGO1_19-1)

Comment: We support the following proposed requirements for book-and-claim accounting for renewable electricity supplied as a transportation fuel:

- Physical traceability would not be required if the renewable electricity is supplied to the grid within a California Balancing Authority.
- Book-and-claim accounting for renewable electricity may span two quarters.
- LCFS credit generators may use book-and-claim accounting to match renewable electricity with charging that is not co-located. This electricity could be generated through the Green Tariffs Shared Renewables program, other community solar or offsite distributed solar programs, or through other contractual relationships.

- LCFS credit generators can retire the Renewable Energy Certificates (RECs) of the renewable electricity that is matched to EV charging to show additionality. (BORREGO1_19-2)

Comment: EDF further supports the development of a mechanism to match EV charging with local renewable energy generation to generate credits using a zero carbon intensity value. Together, these opportunities can expand the range of compliance options available under the program, increase incentive values for consumers, and support continued deployment of renewable energy in California. (EDF1_48-6)

Comment: We support the proposal to allow for indirect accounting for renewable electricity to recognize and encourage the use of renewable electricity and smart charging.

…

Connecting renewable energy to zero emissions vehicles

We support the proposal to allow for indirect accounting for renewable electricity to recognize and encourage the use of renewable electricity and smart charging. Connecting renewable sources of electricity to zero emissions vehicles can maximize the benefits of both the fuel and the vehicle, whether it is solar energy charging a light duty EV or biomethane from a landfill or dairy powering a battery or fuel cell transit bus. Our analysis finds that biomethane generates the lowest carbon emissions when used to produce electricity or hydrogen for battery and fuel cell electric vehicles. See "The Promises and Limits of Biomethane as a Transportation Fuel" for more on this topic (available online at www.ucsusa.org/biomethane-transportation). The safeguards CARB has proposed ensure that the use of renewables will be appropriately documented and will be in addition to requirements of the renewable portfolio standard. (UCS1_53-4)

Comment: Two, we support the proposal to allow for indirect accounting for renewable electricity to recognize and encourage the use of renewable energy and smart charging. (UCS2_T53-4)

Comment: SunPower supports the staff proposal to allow credit generators, such as EV manufacturers and charging station providers, within the electricity pathway to match EV charging with renewable electricity to generate LCFS credits using a zero Carbon Intensity value. This will provide an additional incentive for consumers to make EV purchases as well as support the continued deployment of renewable energy to meet the state's aggressive clean energy and climate goals. (SUNPOWER1_70-3)

Comment: 3. Renewable Energy Matching: approve staff's proposal, with modifications, to allow book-and-claim accounting for renewable electricity supplied as a transportation fuel and allow automakers to generate these credits by matching solar production data with fleet-wide, aggregated charging data from vehicle telematics.

…

III. Approve staff's proposal, with modifications, to allow book-and-claim accounting for renewable electricity supplied as a transportation fuel and allow automakers to generate these credits by matching solar production data with fleet-wide, aggregated charging data from vehicle telematics.

We support staff's proposal to allow credits to be earned based on the matching of recorded residential and non-residential EV charging with renewable solar energy generation. This proposal will boost incentive values for consumers and support continued deployment of renewable energy in California.

The proposed requirements for "indirect accounting for renewable electricity" via "book-and-claim accounting for renewable or low-CI electricity supplied as a transportation fuel" are an improvement over the existing program design, where currently only on-site renewable energy can be matched with charging.[8] Tesla supports the following elements of CARB staff's proposal:

[8] CARB Rulemaking Documents: ISOR Appendix A (p. 156-157)

- Physical traceability is not required as long as the renewable electricity is supplied to the grid within a California Balancing Authority.
- Book-and-claim accounting for renewable electricity may span two quarters, which is reasonable from an administration perspective.
- Credit generators are able to use book-and-claim accounting to match renewable electricity with charging not only through the Green Tariffs Shared Renewables Program but also through other contractual relationships, which allow credit generators other than utilities to participate.
- Credit generators can retire the associated Solar Renewable Energy Certificates (SRECs) of the renewable electricity that is matched, which ensures additionality.

These provisions appropriately balance accountability and additionality with administrative feasibility.

To enhance the clarity of staff's proposal and ensure administrative feasibility, we request three modifications:

- Add language clarifying that an automaker with actual EV charging data and a contractual right to a given quantity of SRECs may match the renewable energy produced with the fleet-wide, aggregated EV charging data to generate incremental LCFS credits. Remove burdensome and overly detailed reporting requirements related to EV charging sessions.
- Remove requirement for parties to disclose pricing information on generation invoices to the Executive Officer, as this information is commercially sensitive and not relevant to the pathway.

- Provide additional guidance on who has the first right to credits in the event of that multiple parties claim credits for the same charging events.

We appreciate CARB staff's proposal to allow credit generators to match EV charging data with off-site renewable energy generation to earn incremental LCFS credits using a 0 CI value. These changes are aligned with California's renewable energy goals and will help spur near-term EV adoption. With the proposed modifications, CARB can provide the necessary guidance to market participants and ensure this new pathway is successful.

…

Based on the foregoing, we believe CARB should … iii) modify the proposed book-and-claim accounting language to ensure a smooth implementation of this pathway,…(TESLA1_79-4)

Comment: And we also support the proposal to basically encourage more renewable adoption in the State by allowing solar and renewable energy to be matched with EV charging under the low-carbon fuel program to generate addition credit. So we support all of those proposals from staff. (TESLA2_T26-4)

Comment: The proposed requirements for "indirect accounting for renewable electricity" via "book-and-claim accounting for renewable or low-CI electricity supplied as a transportation fuel" are an improvement on the existing program design where currently only on-site renewable energy can be matched with charging.[2] We support the following elements of CARB staff's proposal:

[2] CARB Rulemaking Documents: ISOR Appendix A (p. 156-157)

- Physical traceability is not required as long as the renewable electricity is supplied to the grid within a California Balancing Authority.

- Book-and-claim accounting for renewable electricity may span two quarters, which is reasonable from an administrative perspective.

- Credit generators are able to use book-and-claim accounting to match renewable electricity with charging not only through the Green Tariffs Shared Renewables Program but also through other contractual relationships, which allow credit generators besides utilities to participate.

- Credit generators can retire the associated Renewable Energy Certificates (RECs) of the renewable electricity that is matched, which ensures additionality.

These provisions appropriately balance accountability and additionality with administrative feasibility. (SEIA1_119-3)

Comment: 2. We support staff's addition of electricity pathways that recognize the potential to utilize 100% renewable electricity. We urge ARB to implement strong provisions for verify those pathways.

The success of the LCFS is in part due to the ability – within reasonable administrative limits – to recognize the many different potential pathways to reduce carbon-intensity. When coupled with 100% renewable electricity, electric passenger vehicles, trucks, and buses (collectively "EVs") have the potential to be zero-emitting on a lifecycle basis. We support ARB's proposal to recognize additional investments needed to link additional renewable electricity with EV charging.

The Board and staff should continue to monitor the implementation of this new program, whereby staff is proposing a "Green Tariff Shared Renewables Program" (GTSRP) as a way of verifying additional renewable usage. SB100 requires that utilities already increase the renewable electricity mix to 40% renewables by 2030, such that the LCFS should only credit additional, incremental renewable electricity contracts under any type of verification program.

We agree these incremental credits – beyond a baseline – should go to entities that are making the investments that are enabling EV customers to procure the additional renewables and that are providing the necessary verification and reporting data. It is unclear, at this early date, what entity will ultimately be most successful at enabling this effort. We support staff's recommendation to keep this open to either auto manufacturers, utilities, or charging station providers. (NRDC1_81-7)

Comment: Powerex supports expanding the conditions in which a reporting entity may claim renewable energy supplied as a transportation fuel… (POWEREX1_82-1)

Comment: ChargePoint strongly supports the inclusion of Book-and-Claim/Indirect Accounting for Renewable Electricity in this rulemaking cycle. This mechanism will help meet the ambitious carbon reduction targets established in Assembly Bill 32, the California Global Warming Solutions Act of 2006, as well as subsequent amendments and re-adoptions of the Program. In fact, Cerulogy's "California's Clean Fuel Future" report estimated that the addition of the "renewable and/or 'smart' charging" pathways "could deliver an additional 1% to 1.5% carbon intensity reduction." (CHARGEPOINT1_122-1)

Comment: We'd also like to support inclusion of the book and claim indirect accounting for renewable electricity. We think this will make a very large difference in reducing carbon intensity of fuel. (CHARGEPOINT2_T8-3)

Comment: *NextGen Supports Renewable Charging Credits, Provided They Yield Additional Emissions Reductions*

Staff have proposed adding a new LCFS credit pathway, similar to the Smart Charging pathway discussed above. This would function as an additional credit available to EVs which charge using zero-carbon renewable electricity (RE). This proposal would support the continued deployment of renewable energy while also reducing transportation-related emissions. RE credits would be available for charging activity supplied under a Green Tariff rate plan, which procures renewable energy sufficient to meet the customer's aggregate energy needs. (NEXTGEN1_124-38)

Comment: CARB staff is recommending additional LCFS credits for verified renewable electricity. CalETC supports this recommendation but would like CARB to simplify verification for regulated green energy programs (CALETC2_130-2)

> **Agency Response:** Staff appreciates the commenters' support for the proposed indirect accounting of renewable and low-CI electricity. Staff believes this change would promote the use of low CI electricity as a transportation fuel and support further deployment of renewable energy sources. As part of the 15-day changes, staff proposed the use of book-and-claim accounting for low-CI or renewable electricity could span up to three quarters instead of only two quarters.
>
> In response to UCS1_53-4, staff appreciates the commenter's support for the proposed indirect accounting for renewable natural gas and smart charging provisions.
>
> In further response to commenter's suggestion in TESLA1_79-4 to propose a hierarchy for claiming incremental credits and first right in case of multi-party claim, please see Response D-6.14d, Proposed Hierarchy for Incremental Credits for Residential EV Charging, in this chapter.
>
> In further response to commenter's recommendation in TESLA1_79-4 for simplifying reporting for incremental credits, please see Response D-6.14c, Proposed Reporting for Incremental Credits for Residential EV Charging, in this chapter.
>
> In response to NRDC1_81-7, staff appreciates the commenters' suggestion for requiring additionality and verification requirements for book-and-claim accounting of indirect electricity through green tariff shared renewable program. Although SB 100 mandates the percentage renewable for California's grid average electricity resource mix, it does not require that renewable electricity be used for transportation purposes. Staff believes this change would promote the use of low-CI electricity for transportation applications. Staff agrees that accuracy of data reported for credit is critical for ensuring environmental integrity of the program and proposed that the electricity reported for credit generation would be subject to CARB staff audits.

D-6.1m. Multiple Comments: ***Support for the Proposed Measures to Prevent Double Counting***

Comment: We concur with the proposed regulation preventing the simultaneous use of low carbon electricity for both the LCFS and for the California Renewable Portfolio Standard. The programs have distinctively different goals and requirements, and to allow producers to claim both will result in double counting and threaten the overall integrity of the programs. (CBEA1_128-5)

Comment: We concur with the proposed regulation that requires the retirement of all environmental attributes under any other state-based program, *except* the federal Renewable Fuel Standard. The federal RFS is a distinct program unrelated to

California Renewable Portfolio objectives. Moreover, disallowing participation in the federal program would create an unlevel playing field, since current law allows other participants, including RNG producers, with the ability to claim both an LCFS credit and a RIN. That is sound policy and should be extended to renewable electricity. (CBEA1_128-6)

> **Agency Response:** Staff appreciates the commenter's support for the proposed measures to prevent double counting of environmental attributes associated with low carbon or renewable electricity used as transportation fuel. Staff would like clarify that renewable energy certificates or other environmental attributes associated with the electricity, if any, must be retired and not be claimed under any other program with the exception of the federal RFS, and the market-based compliance mechanism set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800).

D-6.2. *Not in Support of the Proposed Electricity Amendments*

Comment: 3. Concerning the broader goals of the LCFS program, the proposed additional electric pathways are borderline *de minimis* in their impacts to meeting the requirements of Executive Order S-01-07. Given the significant bureaucratic burdens associated with each identified pathway, coupled with the complications described above that undermine the effectiveness of the program, these efforts appear to be less a meaningful step towards the state's goals than a desperate attempt to provide incremental credits to keep a marginal program viable. The questionable validity of these electric pathways under E.O. S-01-07 aside, CARB should instead focus on addressing the viability of producing LCFS-compliant fuels, rather than setting untenable regulatory goals, offset by unregulated credit generation. (VALERO1_69b-4b)

> **Agency Response:** Over the years, the LCFS program has expanded in scope to better promote all low carbon transportation fuels. Staff believes there is substantial expectation of growth in the use of electric vehicles, and a considerable portion of travel is anticipated to be done using battery electric vehicles in the future. Given the expected growth in transportation electrification, staff believes that proposed changes would further promote the use of electricity as a low carbon transportation fuel.

D-6.3. Multiple Comments: *Additional Sources of Zero-CI Electricity in Lookup Table*

Comment: 1. Modify the proposed LCFS Regulation to incorporate a new Lookup Table Fuel Pathway in Table 7-1 for electricity used as a transportation fuel that is generated by specified sources other than wind and solar;

…

1. CARB Should Modify the Proposed LCFS Regulation to Incorporate a New Lookup Table Fuel Pathway in Table 7-1 for Electricity Used as a Transportation Fuel that is Generated by Specified Sources Other Than Wind and Solar (BART1_12-1)

Comment: While this recognition of electricity produced by wind or solar resources is an excellent start, the proposed LCFS Regulation should also recognize the efforts of BART and other fixed guideway system operators to reduce the GHG intensity of their public transportation service through the purchase of low or zero carbon intensity electricity generated by other types of generating facilities. As described in Section 95480 of the LCFS Regulation, the purpose of the program is to reduce the carbon intensity of the transportation fuel used in California. While this is certainly accomplished by displacing grid average electricity with electricity from wind and solar resources, it can also be accomplished by displacing grid average electricity from other resources with a carbon intensity that is lower than that of grid average electricity. Thus, the amended LCFS Regulation should encourage procurement of other low or zero carbon intensity sources of electricity as a transportation fuel.

BART acknowledges that some sources of electricity require additional analysis to determine an appropriate carbon intensity value. However, for facilities that qualify as "Specified Sources" under CARB's Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms, 17 Cal. Code Regs. §§ 95801-96022 ("Cap and Trade Regulation"), CARB has already performed much of that analysis. Under the Cap and Trade Regulation, CARB assigns Specified Sources a unique "Emission Factor" intended to reflect the GHG emissions of that generator. Specified Sources include "Asset Controlling Suppliers." 17 Cal. Code Regs. § 95802. Asset Controlling Suppliers are entities that own, operate, or exclusively market a system of electricity generating facilities. 17 Cal. Code Regs. § 95802(a). Asset Controlling Suppliers report comprehensive system and emissions information to CARB, and are assigned a system-wide Emissions Factor by CARB associated with all wholesale electricity sales from the system.

The Emissions Factor assigned by CARB to Specified Sources under the Cap and Trade Regulation is the best available proxy for reporting the carbon intensity of wholesale purchases from Specified Sources under the LCFS Regulation because the data reported pursuant to the Cap and Trade Regulation represents the best available data relating to those electric generating facilities. Wholesale purchasers of Specified Source electricity typically do not have access to other or more detailed information about the emissions of the generating facility. Agreements for the wholesale purchase of electricity from Specified Sources (including Asset Controlling Suppliers) rely on the CARB-assigned identifier for each source to verify the origin of the electricity. In the case of electricity purchased from Asset Controlling Suppliers, the CARB-assigned identifier corresponds to the Asset Controlling Supplier's portfolio as a whole, so the specific generating facilities within the Asset Controlling Supplier's portfolio that are providing the electricity at any given time are not typically identified. As a result, wholesale purchasers rely on the Emissions Factor assigned to the entire system by CARB to monitor and report on the overall CI of their electricity portfolios. Thus, because the purchaser typically does not have access to detailed facility-specific

information, it could be impracticable or impossible for the purchaser to prepare in advance a Tier 2 pathway application that describes lifecycle emissions associated with that electricity on a facility-specific basis in more detail than the Emissions Factor already assigned by CARB under the Cap and Trade Regulation. Additionally, transactions for deliveries of electricity from Specified Sources are often short term, making the development of a Tier 2 application impractical even in the case where the Specified Source is a single generating facility rather than an Asset Controlling Supplier.

Yet, as described above, many Specified Sources that are not wind or solar clearly have significantly lower GHG emissions than grid-average electricity. Moreover, to facilitate the LCFS program's goals, the lower carbon intensity of these non-wind, non-solar Specified Sources as compared to grid-average electricity should be recognized within the LCFS program. In the absence of detailed facility-specific information for Specified Sources, CARB should add new lookup table pathways to Table 7-1 of the LCFS Regulation for electricity from non-wind, non-solar Specified Sources that is supplied as a transportation fuel to fuel reporting entities, and assign those lookup table pathways carbon intensity values equal to the Emissions Factors assigned them by CARB under the Cap and Trade Regulation. (BART1_12-1b)

Comment: To ensure that the contribution of these vehicles is counted towards achieving the GHG reduction goals of the LCFS regulations, San Francisco proposes that the LCFS regulations be changed as follows:

…

2. Zero-GHG hydroelectric resources, both RPS-eligible and large scale, should be included, in addition to solar and wind, as eligible energy sources for the green tariff program;

…

<u>Hydroelectric resources both RPS-eligible and large scale, should be included, in addition to solar and wind, as eligible energy sources for the green tariff program</u>

As noted in the SFPUC's initial comments, all RPS-eligible or zero-GHG resources should be able to be included in CARB's calculation of the CI of electricity provided as a transportation fuel. CARB has included only those resources it identifies as having zero-GHG emissions on a life-cycle basis. Hydroelectric resources, both RPS-eligible and large-scale, meet this definition and should be included under section 95488.1(b)(2)(A), along with wind and solar. CARB itself has recognized the zero-GHG nature of hydroelectric resources in its Mandatory Reporting Requirements (MRR) and cap-and-trade regulations.[2]

[2] Under Section 95101(f)(1) of CARB's MRR regulations: "greenhouse gas emissions reporting is not required for…Electricity generating facilities that are solely powered by nuclear, hydroelectric, wind, or solar energy, unless on-site stationary combustion emissions equal or exceed 10,000 metric tons of CO2e." Under the cap-and-trade regulations, there is no compliance obligation for hydroelectric generation and it is defined as a renewable resource Section 95802(a)).

The LCFS regulations themselves also recognize the zero-GHG life-cycle emissions of hydroelectric resources. Since the start of the LCFS program, CARB has assigned, in its CA GREET models, a zero-GHG emission profile for the hydroelectric portion of electric energy used to produce LCFS fuels.[3] The CA GREET model in turn relies on the U.S. Environmental Protection Agency's E-GRID model which also defines hydroelectric resources as zero-GHG.[4]

[3] "In GREET1 2016, electricity resource mixes are further subdivided: GREET segregates hydropower, wind, solar, and geothermal resource mixes in the category of 'other' electricity resource mixes. In CA-GREET 3.0 the 'other' electricity resources are labeled as, 'other renewable resources.' Biomass is often considered renewable, but requires combustion; nuclear has no combustion, but is not renewable, so these two resource mixes are not included in the 'other' category." (CA-GREET 3.0 Supplemental Document and Tables of Changes. p. 22-23). Following this methodology, the CA GREET 3.0 model assigns zero-GHG emissions to these sources. (***See*** ca-greet3.0.xlms spreadsheet, Electric input tab.)

[4] U.S. EPA Technical Support Document for E-GRID 2016, p. 20

Nowhere in these models has CARB identified any secondary or indirect GHG emissions. Similar to solar and wind resources, hydroelectric resources do not create secondary GHG-emissions evaluated in CARB's life cycle analysis such as; "feedstock production and transport, fuel production, fuel transport and dispensing, co-product production, transport and use; waste generation, treatment and disposal, and fuel use in a vehicle."[5]

[5] **See,** for example, Section 95488.7(a)(2)(B).

There is even less reason for CARB to exclude RPS-eligible hydroelectric resources, certified under California law as RPS-eligible from eligibility under a green tariff program. RPS-eligible hydroelectric resources include small-scale hydroelectric resources (under 30 MW capacity), incremental upgrades to existing facilities, and water conveyance units. This latter category constitutes almost 100% of the SFPUC's RPS-eligible hydroelectric generation. These water conveyance units utilize water that is already flowing through pipelines on its way to serve the SFPUC's customers to create zero-GHG electric generation. At a minimum, these RPS-eligible resources should be included in the Lookup Table Pathway under section 95488.1(b)(2)(A). (CCSF1_87-2)

Comment: …Inclusion of hydroelectric generating resources as an eligible resource under a Green Tariff program

…

(A) Electricity (100 percent solar, wind, or hydroelectric)

…

ELCR	Electricity that is generated from 100 percent solar, wind or hydroelectric generation ~~wind~~ supplied to electric vehicles ~~and fixed guideway systems in California~~	0.00

(CCSF2_90-2a)

Comment: 13. CalETC supports the draft regulation order's proposal for low-CI incremental credits for electricity (both residential and non-residential charging), but suggests a more inclusive definition of renewable and a streamlined process for existing green tariff programs.

…

13. CalETC supports the draft regulation order's proposal for low-CI incremental credits for electricity (both residential and non-residential charging), but suggests a more inclusive definition of renewable and a streamlined process for existing green tariff programs.

The draft regulation order proposes the addition of a new electricity pathway, "ELCR," that is based on 100 percent wind and solar electricity as well as other pathways that are either in-between ELCR and grid-electricity or cleaner than ELCR (e.g., electricity from biogas). Other fuels in LCFS have had very low carbon pathways for several years,[17] so it is appropriate for electricity to similarly have these additional pathways.

[17] Indirect (book-and-claim) accounting that links to renewables is allowed today in LCFS for biomethane, and directed connected accounting for renewables is allowed today for oil refineries, so it is appropriate to allow these methods for electricity. Also biofuels have many possible pathways so it is appropriate for electricity to similarly have multiple pathways.

In addition to our requested amendments above (see comment #8, green tariff electricity), CalETC also suggests that the ELCR – 100 percent wind and solar – pathway be made more inclusive in order to accommodate other renewable, zero-carbon electricity. Specifically, we recommend that additional electricity resources be eligible, consistent with how CARB determines the CI of the state average electricity, so that the section would read:

> "(A) Electricity (100 percent solar, ~~or~~ wind, geothermal, biomass, hydroelectricity, or other zero-GHG-?emissions resources, or any combination thereof)
>
> (F) Hydrogen (gaseous) from electrolysis using electricity generated from 100 percent solar-, ~~or~~ wind-, geothermal, biomass, hydroelectric or other zero-GHG-emission resources, or any combination thereof) ~~generated electricity.~~"

Many EDU's green tariff programs contain additional renewable resources, beyond wind and solar, sources that provide equivalently low-carbon electricity. Enabling additional green tariff programs to participate would reflect the full portfolio of renewable resources in California and participation in this optional pathway.

CalETC also suggests reviewing the data and bringing any improved methodologies to the Board should the data suggest improvements are possible. (CALETC1_96-16)

Comment: §95488.1 Fuel Pathway Classifications

To support additional LCFS credit generation, PG&E appreciates the inclusion of additional fuel pathways in section 95488.1(b)(2)(A) through (F).[7] However, regarding

sections 95488.1(b)(2)(A) and (F), we are concerned that CARB's proposal is overly narrow, technology-specific and not fuel-neutral. We recommend that these fuel pathways be made broader to include other sources of zero-carbon electricity consistent with how CARB determines the CI of the California grid, so that the section reads:

> "(A) Electricity (100 percent solar, ~~or~~ wind, geothermal, biomass, hydroelectricity, or other zero- GHG-emissions resources, or any combination thereof)
>
> …
>
> (F) Hydrogen (gaseous) from electrolysis using electricity generated from 100 percent solar-, ~~or~~ wind-, geothermal, biomass, hydroelectric or other zero-GHG-emission resources, or any combination thereof) ~~generated electricity~~
>
> [7] (A) Electricity (100 percent solar or wind)

(PGE1_120-19)

Comment: Since all renewable generation results in avoidance of carbon emissions, all renewable generator types that qualify as an Eligible Renewable Resource (ERR), as such term is defined in PUC Code Section 399.12 or 399.16 (not just solar and wind) should be eligible to qualify for lower carbon intensity fuel pathway values. 3 Phases believes including such generation will provide not only an added incentive for bringing all types of renewable projects online (including much needed baseload renewable generation), but also provide a more accurate CI score and create consistency with well-established California regulations. CARB is already quantifying the CI benefits from all types of renewable generation when it calculates the baseline carbon intensity. To facilitate consistent calculation of CI scores, CARB should provide lookup values for any renewable generation type that qualifies as an ERR. (3PR1_31-6)

Comment: Additionally, the green tariff is only open to the use of solar and wind resources. This excludes other RPS-eligible resources, such as biomass, geothermal, and in some cases, hydroelectric resources. These RPS-eligible resources should be included in the green tariff definition. (SEVCG1_116-6d, SEVCG2_B10-6d)

> **Agency Response:** In response to these comments, staff modified the Regulation language to allow additional sources of zero-CI electricity used as a transportation fuel to be reported using the Lookup Table pathway which was limited to "solar or wind" electricity in the original proposal and has a CI value of zero. Staff's modified proposal includes RPS-eligible electricity (i.e., electricity from "eligible renewable energy resources" as defined by the California Public Utilities Commission (CPUC) under California's Renewable Portfolio Standard, CPUC sections 399.11-399.36), but excludes biomass, biomethane, geothermal and municipal solid waste-derived electricity, as these may have non-zero emissions and must be evaluated through the Tier 2 application process. Other electricity generation methods may also be able to achieve a zero CI, but must apply using the Tier 2 application process. As explained in the notice of changes, "staff examined electricity generation pathways in GREET, and

generation sources that meet eligibility for California's Renewable Portfolio Standard,[2] to determine all sources that are expected to achieve a zero CI. Stakeholders also requested the addition of geothermal and biomass power as zero-CI sources; however, these sources are low-CI, yet typically result in some (non-zero) emissions."

[2] Renewables Portfolio Standard Eligibility Guidebook. Eighth Edition. California Energy Commission, June 2015. Available at: http://www.energy.ca.gov/2015publications/CEC-300-2015-001/CEC-300-2015-001-ED8-CMF.pdf

Staff note that renewable or low-CI electricity that may be indirectly supplied through book-and-claim accounting is not limited to zero-CI sources. Although the Green Tariff Shared Renewables program is currently limited to solar electricity, staff's proposal to allow the use of "a green tariff program (including the Green Tariff Shared Renewables program described in California Public Utilities Code Section 2831-2833) or other contractual low-CI electricity supply relationship" that meets the requirements of section 95488.8(i)(1)(B) is not limited to zero-CI sources. Therefore, a particular generation source, or a mix of sources provided through a green tariff program, may apply for a CI score using either the Lookup Table, if it is a source listed under section 95488.1(b), or a Tier 2 pathway application.

Emission factors assigned by CARB to Specified Sources under the Cap-and-Trade Regulation represent direct emissions, not life cycle emissions, and therefore, cannot be used as a proxy for carbon intensity values in the LCFS program.

D-6.4. Multiple Comments: *Indirect Accounting for Renewable Electricity*

D-6.4a. Comment:

(B) Renewable or Low-CI electricity can be indirectly supplied through a green tariff program (including the Green Tariff Shared Renewables program described in California Public Utilities Code Section 2831-2833) or other contractual low carbon electricity supply relationship that meets the following requirements:

1. Electricity is generated using equipment owned by, or under contract to the pathway applicant for all environmental attributes of the project. In order to substantiate renewable electricity claims, the applicant must make contracts available to the Executive Officer, upon request, to demonstrate that the electricity meets the requirements of this subarticle. Generation invoices or metering records are required to substantiate the quantity of renewable electricity produced from the renewable assets. Monthly invoices must be unredacted copies of originals showing electricity sourced (in kWh) and contracted price;

…

3. Renewable energy certificates or other environmental attributes associated with the energy that is needed for compliance with the California Renewables Portfolio Standard or, for hydrogen produced outside of California, to meet local renewable portfolio requirements must be retired and not claimed under any other program with the exception of the federal RFS.

…

5. Any Renewable energy ~~electricity~~ certificates or other environmental attributes associated with the energy that is in addition to that needed for compliance with the California Renewables Portfolio Standard or, for hydrogen produced outside of California, in addition to local renewable portfolio requirements must be ~~if any, are~~ retired and not claimed under any other program with the exception of the federal RFS and to verify green tariff claims.

(CCSF2_90-2c)

Agency Response: The commenter proposed the addition of the text shown above in double underline and ~~double strikethrough~~ format, in section 95488.8(i)(1)(B) of the originally proposed regulation released March 6, 2018.

In response to this comment and others which indicated confusion about the meaning of low-CI and the eligibility of renewable resources, staff added a definition of low-CI electricity to section 95481(a). In subsection (B) proposed by the commenter, staff believes the addition of "Renewable or" is not necessary, as the term "low-CI" electricity is inclusive of RPS-eligible renewable electricity. Staff prefers the term "low-CI" because CI performance relative to the annual carbon intensity standard is the metric by which fuel pathways are evaluated under the LCFS; whether a fuel is renewable or non-renewable is not considered in credit or deficit generation.

In paragraph 1. staff agrees with the commenter that metering records are acceptable documentation of the quantity of electricity produced from the equipment.

In paragraphs 3. and 5., staff's understanding is the commenter is concerned about investor-owned utilities reporting to CPUC the electricity or renewable energy credits that are retired to demonstrate compliance with the Green Tariff Shared Renewables program. Staff's intention is to ensure that electricity that receives LCFS credit using book-and-claim accounting is above and beyond the RPS requirements in California (and in other jurisdictions, for renewable hydrogen that is imported to California), and that the environmental attributes are not double claimed, i.e., matched to other (non-transportation) end uses. Staff

has clarified that the prohibition on double counting does not include CPUC reporting for the Green Tariff Shared Renewables program.

D-6.4b. Multiple Comments: ***Indirect Accounting for Electricity or Biomethane Used as Process Energy***

Comment: Also, perhaps expanding the role of renewable power. Everyone recognizes the unique role of hydrogen and electric vehicles. But there's an opportunity, for example, with ethanol plants that produce animal feed, you could bring the manure back to the ethanol plant and run it in a digester, which would require millions of pounds of manure, thousands of truck trips; or you could put it into a digester -- put it into an engine. The electrons weigh less than these glasses. Put it in the grid, and it's still a closed loop, and that's an opportunity to get methane reductions that, quite frankly, otherwise would never occur without the value of the LCFS credit. (LCA5_T38-2)

Comment: CARB proposes to allow wind/solar power generation CI reduction credit at fuel production facilities only when the renewable power is directly connected to the fuel production facility. CARB also proposes allowing CI reduction credit for renewable electricity for ZEV charging at stations not directly connected to the renewable electricity source.

1. *CARB should treat parties equally either: (a) by allowing renewable electricity credits to be acquired and retired for use in reducing carbon intensity at fuel production facilities; or (b) by requiring ZEV charging stations be directly connected to a renewable electricity source to receive credit.*

CARB has required fuel production facilities to have renewable electricity production directly connected to fuel production facilities in order to receive CI reduction credit. CARB does not provide justification for providing more favorable treatment to other transportation energy sources. (FHR1_18-4)

Comment: We strongly endorse the comments from ACE-member RPMG Inc, a biofuel marketing company, with respect to the unfair preferential treatment provided by §95488.8(i)(1) Book and Claim Accounting, which specifically allows for “indirect accounting mechanisms for renewable electricity to reduce the CI of electricity supplied as transportation fuel or for hydrogen production through electrolysis.” This preferential treatment is further disallowed in §95488.8(h) Renewable or Low CI Process Energy, prohibiting indirect accounting mechanisms for renewable or low-CI process energy to reduce CI for all other low carbon fuel types.

CARB indicates this assistance is necessary for electricity because there has been very little interest in ZEV pathways under the current rule. But by tipping the scale, the proposed regulation is not “allowing the market to determine how the carbon intensity of California’s transportation fuels will be reduced.”

Under the proposal, a reporting entity may generate credits for renewable electricity supplied to the grid in the previous quarter, despite having no physical traceability.

While the LCFS proposal extends this benefit to electricity and hydrogen pathways, it requires burdensome traceability and verification requirements for other fuel pathway holders or the use of conservative default values which puts the economic viability of many pathways into question. ACE joins RPMG in urging CARB to revise and extend these forms of indirect accounting mechanisms to all pathway types for process energy.

Preferential treatment for one isolated source of low carbon fuel undermines the effectiveness of the LCFS and violates the fuel neutrality and performance-based principles which have served the program to-date so well. (ACE1_41-3a)

Comment: RPMG strongly advises that the proposed regulations be revised to extend the use of indirect accounting mechanisms to all pathway types for process energy. There is preferential treatment provided in **§ 95488.8 (i)(1) Book-and-Claim Accounting,** which specifically allows for "indirect accounting mechanisms for renewable electricity to reduce the CI of electricity supplied as transportation fuel or for hydrogen production through electrolysis." This preferential treatment is further disallowed in **§ 95488.8 (h) Renewable or Low – CI Process Energy** prohibiting indirect accounting mechanisms for renewable or low-CI process energy to reduce CI for all other low carbon fuel types. The ISOR states this assistance is necessary because there has been very little interest in such ZEV pathways under the current rule. By tipping the scale, the proposed regulation is not "allowing the market to determine how the carbon intensity of California's transportation fuels will be reduced."

Under the proposed regulation, a reporting entity may generate credits for renewable electricity supplied to the grid in the previous quarter, despite having no physical traceability. While the LCFS proposal extends this benefit to electricity and hydrogen pathways, it requires other fuel pathway holders to go great lengths to trace and verify the source of their feedstock, have a direct connection to renewable power, or use a default value so conservative it may put the economic viability of many pathways into question. RPMG strongly advises the proposed regulation be revised to extend these forms of indirect accounting mechanisms to all pathway types for process energy. (RPMG1_64-5)

Comment: Renewable or Low-CI Process Energy Balancing:

Due to the seasonal variability of production of certain renewable resources (solar in particular), to calculate a CI score, 3 Phases believes an annual reporting calculation will be more consistent with GHG reporting than a monthly one, as described in Section 95488.8(h)(1)(C). Additionally, 3 Phases makes the same argument when Indirect Accounting is used for claims; 3 Phases believes that an annual reporting calculation should be used instead of the two-quarter limitation described in 954888.8(i)(1)(A). Given that the carbon intensity score for the grid is calculated, by CARB, on an annual basis it is appropriate that the timeline for credit balancing be on an annual basis to account for seasonal production variances. (3PR1_31-2)

> **Agency Response:** Staff's proposed amendments recognize the benefits of biomethane or renewable electricity that is used as process energy if the fuel is

directly supplied to the fuel production facility. Book-and-claim accounting is not recognized for indirectly supplied renewable or low-CI process energy to lower the carbon intensity in the production step of alternative fuels. This is due in part to the difficulty of tracking and verification across all locations where alternative fuels are produced to serve California, but also because the focus of the program is to incent the use of alternatives directly as transportation fuel; other programs exist to incent the use of biomethane for electricity production without regard to end use..

In response to FHR1_18-4, ACE1_41-3a, and RPMG1_64-5, CARB is committed to increasing demand for low carbon fuels and recognizes GHG benefits from directly using low carbon fuels and electricity as process energy in alternative fuel production.

However, staff disagrees that allowing indirect accounting for electricity used as a transportation fuel is inappropriate. As stated in the ISOR, “the CI of pathways for electricity supplied to vehicles, and hydrogen produced by electrolysis rely almost entirely on the source of the electricity, but no options exist under the current regulation for matching low-CI electricity to an EV or electrolysis load. For electric vehicles and hydrogen stations, opportunities for collocation of low-CI electric generation assets may be limited due to small land-area footprints. Additionally, book-and-claim accounting (mass balance without regard to physical traceability) has been recognized for biomethane, but not electricity.”

Pathways for electricity used directly as a transportation fuel and for hydrogen produced by electrolysis use electricity as a feedstock. Staff views the flexibility for indirect accounting of low-CI electricity for these pathways as analogous to the flexibility that the LCFS has always offered to other biofuels in using a mass balance approach to allocation of finished fuel to various feedstocks. In this regard, electricity has historically been disadvantaged in the program by being limited to the regional grid CI. Additionally, these changes create consistency between the treatment of biomethane that is indirectly supplied through the common carrier pipeline, and renewable electricity that is supplied through the electrical grid.

Staff did not accept the recommendation to recognize book-and-claim accounting for process energy use due to the following reasons:

1. There are several other policies and programs such as renewable portfolio standards that support lower-CI stationary electricity generation.

2. For out-of-state fuel production facilities, it is difficult to track, monitor and verify electricity transactions due to different state-specific rules and regulations. If indirect accounting were allowed for renewable or low-CI process energy, it would put strain on limited staff resources to carryout proper fuel pathway evaluations or greatly increase costs for more comprehensive third-party verification.

3. The GHG benefits of allowing indirect accounting for renewable or low-CI process energy are expected to be relatively small as most alternative fuel production does not rely extensively on electricity consumption.

In response to 3PR1_31-2, the purpose of monthly balancing is to establish a link with renewable electricity production. If the period of electricity use is far removed from the period of renewable electricity production, it is difficult to justify that produced renewable electricity is actually used in fuel production. Through monthly balancing, it is possible to closely tie the renewable electricity production with its use. The monthly balancing is used in the different context in 95488.8(h)(1)(C) than annual reporting.

D-6.4c. *Low-CI or Renewable Electricity as Process Energy*

Comment: AECA seeks greater clarity on the ability for projects to utilize solar generation in a net energy metering arrangement to replace grid power to meet the energy requirements of biomethane clean-up, conditioning, and compression equipment. Greater clarity is needed to ensure renewable energy can appropriately be included in the CI calculation for proposed project pathways. (AECA1_72-12)

Agency response: Renewable or low-CI electricity generation that is on-site or directly supplied behind the meter is recognized for use as process energy at a production facility to reduce the CI of a transportation fuel. The regulation allows for a one-month balancing period to demonstrate that the facility's load is sufficient to match the amount of low-CI electricity that is claimed. Net metering arrangements vary across EDU service areas, and therefore, staff must evaluate the arrangement and documentation for each application to ensure that grid and non-grid consumption is verifiable. Staff expects that utility invoices should accurately report the quantity of grid electricity that is consumed, but additional metering and documentation including contracts may be requested.

D-6.5. *Clarification for Indirect Accounting for Renewable or Low-CI Electricity using Book-and-Claim Principle*

D-6.5a. Comment: To further enhance the clarity of this section and ensure administrative feasibility, we request three clarifications:

- CARB should clarify that a credit generator with accurate EV charging data and a clear contractual right to the underlying renewable electricity produced by generation equipment may match the renewable energy produced with the EV charging data to generate incremental credits.
- CARB should provide additional guidance on who has the first right to credits in the event of that multiple parties claim credits for the same charging event.
- CARB should reconsider requiring pricing information on generation invoices provided to the Executive Officer because this information is commercially sensitive.

We appreciate CARB staff's proposal to allow credit generators to match EV charging with off-site renewable energy generation to generate credits using a 0 CI value. These changes are aligned with California's long-term renewable energy goals and will help spur near-term EV adoption. With the proposed clarifications, CARB can provide the necessary guidance to market participants and ensure this pathway's success. (SEIA1_119-4)

> **Agency Response:** As part of the 15-day changes, staff clarified the requirements for claiming incremental crediting in section 95491(d)(3)(A), and proposed a hierarchy for claiming incremental credits in section 95483(c)(1)(B). ARB retains the right to request records affiliated with the contractual agreements established to obtain renewable attributes associated with book-and-claim accounting. Unredacted copies of these invoices are necessary to verify claims and identify if fraud or abuse has occurred. ARB regularly handles business confidential data which is used internally and is not made publicly available.

D-6.5b. Comment: On p 167 it says:

Any fuel pathway holder, including a joint applicant, who is not subject to site visits by a third party verifier, whose pathway involves the use of renewable or low-CI process energy, must submit invoices for that energy to the AFP. Additionally, for any electricity that is used to reduce carbon intensity of electricity for EV charging or hydrogen production via electrolysis, the pathway holder must upload records demonstrating that any RECs generated were retired in WREGIS for the purpose of LCFS credit generation.

This section appears to be existing pathway holders, which we are not, however it does seem to hint that reducing the CI of electricity is possible by retiring RECs in WREGIS. Is this limited to on-site/co-located renewable energy production? (ITM1_2-1)

> **Agency Response:** Entities can reduce the carbon intensity of electricity for electricity supplied as a transportation fuel or hydrogen production using electrolysis by indirectly matching low-CI electricity to the load using book-and-claim accounting. Under this provision the renewable electricity production is not required to be co-located with the load. One allowable method of doing this is by retiring RECs in WREGIS. These RECs must be retired on behalf of the LCFS and cannot also be used to comply with the California Renewable Portfolio Standard.

D-6.5c. Multiple Comments: ***Clarification for Indirect Accounting for Renewable or Low-CI Electricity using Book-and-Claim Principle***

Comment: 3. Clarify the requirements for book-and-claim accounting for low- and zero-CI electricity reported by eligible fuel reporting entities; and

…

3. CARB Should Clarify the Requirements for Book-and-Claim Accounting for Low and Zero-CI Electricity Reported by Eligible Fuel Reporting Entities

Proposed Section 95488.8(i)(1)(B) allows for book-and-claim accounting to be used to report low-CI electricity used as a transportation fuel, where the electricity is supplied by contractual relationship that meets certain requirements. Paragraph 1 of that section requires that the "Electricity is generated using equipment owned by, or under contract to the pathway applicant for all environmental attributes of the project." Read literally, this language could be interpreted to mean that the buyer is required to purchase all of the environmental attributes of a given project, even if the buyer is purchasing only a portion of the output from that project. However, BART believes that CARB staff intended for this requirement to be satisfied through commercial transactions where the buyer purchases all of the environmental attributes associated with the electricity it is purchasing.

CARB staff should clarify this regulatory language to make clear that it requires only the purchase of all environmental attributes associated with the electricity purchased by the buyer, and not all of the output of a given facility. (BART1_12-3)

Comment: We request that CARB clarify that the following statement does not preclude a pathway applicant from contracting a portion of available renewable electricity from a provider:

> Section 95488.8(i)(1(B)(1): *Electricity is generated using equipment owned by, or under contract to the pathway applicant for all environmental attributes of the project.*

For example, in the event that a pathway applicant contracts (through a PPA with the operator or through a utility Green Tariff) to utilize 30MW of a total available 100MW from a renewable generator, the renewable power should be credited in the CI calculation even though the applicant is not purchasing all of the power generated by the project. (AL1_39-3)

> **Agency Response:** Staff appreciates the commenters' recommendation. As part of the 15-day changes, staff proposed to clarify that an entity claiming low-CI electricity through a green tariff program needs to demonstrate the right to the environmental attributes only for the claimed quantity of electricity.

D-6.5d. Comment: We recommend two minor modifications:

- CARB should clarify that the LCFS credit generator does not need to own the underlying renewable electricity generation equipment in order to have a clear right to the renewable attributes (i.e. RECs) of the renewable electricity produced.
- If generation invoice information is provided to the Executive Officer, pricing information should not be required due to the sensitivity of that information. (BORREGO1_19-3)

Agency Response: As part of the 15-day changes, staff clarified that the entity claiming renewable or low-CI electricity through indirect book-and-claim accounting need not own the underlying generation asset but must be able to demonstrate the right to environmental attributes for the claimed electricity through contracts or through REC retirement. Staff also proposed that upon request by the Executive, unredacted copy of monthly invoices must be provided to substantiate the low-CI electricity claimed. Staff understands the commenter's concern about reporting market sensitive information; however, staff would like to note that LCFS reporting tools are secured and equipped for transmitting market sensitive and business confidential information.

D-6.5e. Comment: The Proposed Amendments should explicitly clarify that the ARB can rely on actual LSE carbon intensity documentation in addition to REC retirement. In the case of REC retirement, the final Regulation must be administratively feasible and efficient.

...

A. The Smart EV Charging Group supports establishing a method for reflecting incremental improvements in CI for EV charging, in addition to REC retirements.

The per-vehicle LCFS credits have been historically granted exclusively to the EDUs supplying electricity for residential EV charging. The credits represented the emissions reductions associated with replacing a gasoline vehicle with an EV and were based on the assumption that the EV was charged at the statewide average rate of emissions for the electric sector. This framework reflected assumptions that: 1) all electric supply portfolios had uniform emissions; 2) EDUs were the sole drivers of marginal EV adoption in their service territories; 3) the EDUs were solely responsible for procuring electricity to supply the EVs; and 4) the EDU's ability to provide rebates would spur new EV deployment. These assumptions may have been appropriate at the outset of the LCFS program, but they do not accurately reflect California's current EV and electricity landscape.

…

The Proposed Amendments should be refined to better acknowledge the ability of CCAs and EVSPs to quickly enact EV and transit programs. The Proposed Amendments should also better reflect the fact that the CI of electricity used for EV charging is directly affected by its source and by time of use.

As noted in the Smart EV Charging Group's December 4, 2017 comments the Smart EV Charging Group agrees with the fundamental logic of allowing the generation of incremental credits that reflect the delta between: 1) credits reflecting the statewide CI of electricity used for residential charging, and, 2) the lower CI of electricity supplied by an LSE (specifically new and emerging CCAs), onsite renewables, or reflecting time of use. To implement this, the Proposed Amendments would create a Tier-2 process where incremental low-CI EV credits would go to any party that can substantiate

charging by a CARB approved green tariff program, or other contractual low-CI electricity supply relationship, so long as the RPS or other environmental attributes are not retired or counted towards other compliance requirements.[1] As GHG emissions are directly reflected by carbon intensity we continue to support GHG-based accounting and verification. While both EDUs and CCAs currently have RPS compliance obligations, the regulations should account for the fact that in the future, utilities will likely be measured by the carbon intensity of their portfolios, not just RPS compliance. This is the intent of AB 32, SB 32, SB 350, AB 1110 and the IRP processes.

[1] See section 95488.8(h)-(i).

While we do not dispute the use of the renewable attributes, or "RECs", such as used for RPS compliance, for measuring LCFS credits as one pathway to establishing incremental low-CI credits, we believe that the ARB should be clearer that other carbon-based accounting metrics can be used to generate incremental credits. We propose that the Regulatory Language be amended to reflect that, in a future GHG-based compliance framework, incremental credits for clean charging are applied to CI reductions below the state-wide average. That is, if 300 lbs/MWh is the state-wide average, an LSE with a supply of 200 lbs/MWh would be able to apply the difference – 100 lbs/MWh – to generate LCFS credits.

The Smart EV Charging Group understands the staff's proposed amendments are intended to create a flexible process that would allow for this type of carbon-based accounting in a Tier-2 application. Assuming this understanding is correct, the Proposed Amendments to sections 95483(c), 95483.1, 95486.1(c), and 95488.8 generally present a reasonable approach but should be revised to make clear that other CI accounting metrics can be used in place of the REC retirement process. Please see Attachment 2, Section I.

…

I. Adopt the proposed approach of allowing the calculation of incremental credits reflecting improvements (over the California Average Grid Electricity Pathway) in carbon intensity of electricity by amending Section 95488.8(h) and (i) as follows:

(h) Renewable or Low-CI Process Energy. Except as ~~Unless~~ expressly provided Subsection 95488.8(i) ~~elsewhere in this subarticle,~~ indirect accounting mechanisms for renewable or low-CI process energy, such as the use of renewable energy certificates, cannot be used to reduce CI. In order to qualify as a low-CI process energy source, energy from that source must be ~~directly consumed in the production process~~ directly supplied to serve end use load as described in (1) and (2) below

. . .

(i) Indirect Accounting for Renewable Electricity and Biomethane.

(1). Book-and-Claim Accounting for Renewable or Low-CI Electricity Supplied as a Transportation Fuel or Used to Produce Hydrogen. Reporting entities may use indirect accounting mechanisms for renewable electricity to reduce the CI of

electricity supplied as a transportation fuel or for hydrogen production through electrolysis, provided the conditions set forth below are met:

(A). Reporting entities may report electricity dispensed to electric vehicles or as an input to hydrogen production (including for purposes of the Renewable Hydrogen Refinery Credit) as renewable electricity without regard to physical traceability if it meets all requirements of this subdivision. The renewable electricity must be supplied to the grid within a California Balancing Authority (or local balancing authority for hydrogen produced outside of California). Such book-and-claim accounting for renewable electricity may span only ~~two~~ four quarters. If a renewable or low-CI electricity quantity (and all associated environmental attributes, including a beneficial CI) is supplied to the grid in one calendar quarter, the quantity claimed for LCFS reporting must be matched to grid electricity dispensed to electric vehicles or for hydrogen production no later than the end of the following three calendar quarters. After that period is over, any unmatched renewable or low-CI electricity quantities expire for the purpose of LCFS reporting.

(B). Low-CI electricity can be indirectly supplied through a green tariff program (including the Green Tariff Shared Renewables program described in California Public Utilities Code Section 2831-2833) or other contractual low carbon electricity supply relationship that meets the following requirements:

1. Electricity is generated using equipment owned by, or under contract to the pathway applicant for all environmental attributes of the project. In order to substantiate renewable electricity claims, the applicant must make contracts available to the Executive Officer, upon request, to demonstrate that the electricity meets the requirements of this subarticle. Generation invoices, contract and/or meter data are required to substantiate the quantity of renewable or low-CI electricity produced from the renewable assets. Monthly invoices must be unredacted copies of originals showing electricity sourced (in kWh) and contracted price;

2. All electricity procured by any LSE for the purpose of claiming a lower CI must be in addition to that required for compliance with the California Renewables Portfolio Standard or, for hydrogen produced outside of California, in addition to local renewable portfolio requirements;

3. Renewable electricity certificates or other environmental attributes associated with the energy, if any, are retired and not claimed under any other program with the exception of the federal RFS.

4. An LSE may supply other information through a Tier 2 application process to establish low-CI electricity based on the annual, historic carbon intensity of the LSE's portfolio compared to the statewide grid average. (SEVCG1_116-3, SEVCG2_B10-3)

Agency Response: Staff appreciates the support for using indirect accounting mechanisms for environmental attributes associated with electricity as a transportation fuel. Consistent with section 95488.8(i)(1)(B), applicants must submit generating invoices or metering records to substantiate low-CI electricity sourced from low-CI assets. A Tier 2 electricity pathway will not be assessed in the absence of the records required in the section above, regardless of whether another program has already calculated an emission factor for this electricity source.

D-6.5f. Comment: 4. Clarify that Lookup Table Fuel Pathways may be claimed for the corresponding portion of a fuel reporting entity's electricity portfolio

…

4. CARB Should Clarify That Lookup Table Pathways May Be Claimed for a Portion of a Fuel Reporting Entity's Electricity Portfolio

Many fuel reporting entities that report electricity used as a transportation fuel procure their electricity from a portfolio of various sources. A fuel reporting entity may find that part, but not all, of its electricity procurement portfolio qualifies for reporting under a particular lookup table pathway. For example, a fuel reporting entity might procure sixty percent (60%) of the electricity it uses for transportation fuel from solar-powered electric generating facilities, with the remaining forty percent (40%) procured from non-specific sources. The draft LCFS Regulation is unclear on how a fuel reporting entity should report its electricity use in this case.

Based on a review of the proposed LCFS Regulation revisions as a whole, BART believes that CARB intends that a fuel reporting entity will be authorized to submit a lookup table fuel pathway application under draft Section 95488.5 for a portion of its electricity portfolio, provided that it adequately demonstrates that such electricity meets the requirements of Section 95488.8(h) (for renewable, low-CI, or zero-CI electricity directly consumed in the production process) or Section 95488.8(i) (for renewable, low-CI, or zero-CI electricity that meets the requirements for book-and-claim accounting), as well as any other applicable fuel pathway application requirements set out in draft Section 95488.8. BART understand that a fuel reporting entity may therefore submit several fuel pathway applications with respect to distinct portions of its overall electricity portfolio. Using the example described above, BART's understanding is that the fuel reporting entity could submit a fuel pathway application for the sixty percent (60%) of the portfolio that is supplied from a solar-powered electric generating facility and apply the associated CI of 0 for this portion of its portfolio, while reporting the remaining forty percent (40%) of the portfolio as grid-average electricity and applying the associated CI of 93.42. BART respectfully requests that CARB clarify, either in the draft LCFS Regulation or staff's Final Statement of Reasons, that this understanding of the draft LCFS Regulation is correct. (BART1_12-4)

Agency Response: Staff agrees with the commenter that a fuel reporting entity may submit several fuel pathway applications with respect to distinct portions of its overall electricity portfolio.

D-6.6. Multiple Comments: ***Indirect Book-And-Claim Accounting for Low-CI or Renewable Electricity for Hydrogen Production***

D-6.6a. Comment: Green Energy Tariff programs have the potential to open market opportunities for renewable hydrogen production, compression, liquefaction, distribution or dispensing. We recommend the LCFS Regulations be broadened to allow recognition of renewable electricity purchased under Green Tariffs from the utilities; within and outside California; and to include future programs. By leveraging the broader power agreements available in the region, we anticipate being able to provide lower cost renewable hydrogen along a more accelerated timeline than with the current limitations. (AL1_39-2)

Agency Response: As part of the 15-day changes, staff proposed an option to allow low-CI electricity to be eligible for indirect accounting as long as it meets the interconnection or scheduling/delivery requirements of California Public Utilities Code section 399.16, subdivision (b)(1). Staff would like to clarify that with regards to electricity used for hydrogen production, book-and-claim accounting for indirectly supplied renewable or low-CI electricity is allowed only for the electricity used for electrolytic production of hydrogen to be used as transportation fuel or to be used for production of other transportation fuel. Electricity used for compression, liquefaction, distribution, or other ancillary services at a hydrogen production or station facility is not eligible for book-and-claim accounting.

D-6.6b. Comment: Low Carbon Electricity Supply:

The language in Section 95488.8(i)(B) is somewhat ambiguous regarding which programs need to meet subsections 1-3. 3 Phases suggests that CARB remove ambiguity to ensure a green tariff program must also meet the requirements expected of "other contractual low carbon electricity supply relationship(s)". (3PR1_31-3)

Agency Response: Staff would like to clarify that any low-CI electricity indirectly supplied through a green tariff program or other contractual electricity supply relationship must meet the requirements set forth in sections 95488(i)(1)(B)1. through 3.

D-6.7. ***Demonstrating Indirect Book-and-Claim Accounting for Renewable or Low-CI Electricity through REC Retirement***

D-6.7a. Multiple Comments: ***Demonstrating Indirect Book-and-Claim Accounting for Renewable or Low-CI Electricity through REC Retirement***

Comment: Substantiating Proof of Renewable Electricity Sourced:

3 Phases agrees with the language in Section 95488.8(i)(1)(B)(3) regarding the requirement for renewable electricity certificate (REC) retirement. The REC retirement process could be done specifically for the LCFS program using the Western Renewable Energy Generation Information System (WREGIS). The California Renewable Portfolio Standard (RPS) currently requires proof of WREGIS Certificate retirement, so using WREGIS to quantify renewable generation claims for the LCFS program would maintain consistency with the RPS program. Further, 3 Phases believes that WREGIS Certificate retirement should be sufficient to substantiate the quantity of renewable electricity produced from specific renewable assets and that generation invoices should not be required, as described in 95488.8(i)(1)(B)(1), because WREGIS already has strict metering requirements to prove that WREGIS Certificate quantities match renewable generation. (3PR1_31-4)

Comment: B. The Smart EV Charging Group recommends revisions and clarifications for use of REC retirements to support Incremental Credit generation.

Eligible renewable attributes for purposes of the Low Carbon Fuel Standard program should be consistent with the rules of California's Renewable Portfolio Standard (RPS) and utilize Western Renewable Energy Generation Information System (WREGIS) for registration, tracking, trading and retirement. Renewable attributes could be retired with the stated purpose of "LCFS", which could be established with WREGIS formally. The vintage of the generation producing the renewable attribute would be associated with the retirement transaction. ARB should allow for non-Fuel Reporting Entities to initiate the retirement transaction at WREGIS on behalf of a Fuel Reporting Entity, similar to convention in the voluntary renewable attribute procurement market.

The Smart EV Charging Group recommends that the data required to support retirement transactions be reasonable and not overly burdensome. Reports from WREGIS showing proof of renewable attributes retirement should be sufficient.

ARB has proposed that renewable attributes must be generated within the last two calendar quarters in order to apply for Incremental Credits resulting from EV charging. Given the processes at WREGIS, there is typically a one quarter lag between renewable generation and when the renewable attribute is available at WREGIS for transactions. As a result, there may only be one quarter of generation available for matching with EV charging volumes. ARB should examine whether additional latitude can be granted to Fuel Reporting Entities to provide an actual four quarters' range of data. In addition, the Fuel Reporting Entity should have until 90 days after the calendar quarter to provide evidence of retirements, even if Fuel Transactions have already been submitted to the ARB.

Finally, in order to avoid unnecessarily burdensome administration by Fuel Reporting Entities and ARB Staff, the Tier 2 Pathway application process should be waived for Entities utilizing WREGIS retirement transactions to generate Incremental Credits. Fuel Reporting Entities should be able to utilize an "Offsite Renewable Energy Generation" option from the drop-down menu or spreadsheet template for the Fuel Transactions reporting process. As long as the Fuel Reporting Entity provides confirmation of the

equivalent renewable attribute retirements at WREGIS with the stated purpose of LCFS, then these Incremental Credits should remain deposited in the Entity's balance account. If such confirmation is not provided, then the Incremental Credits could be nullified by ARB. ARB should define a simple way to provide this confirmation within the current reporting system and processes, if possible, and avoid a requirement that a Tier 2 Pathway application would be filed for every Fuel Station Equipment Facility location seeking to utilize an "Offsite Renewable Energy Generation" carbon intensity value. (SEVCG1_116-3b, SEVCG2_B10-3b)

> **Agency Response:** Staff appreciates the commenter's support for the proposed requirement to demonstrate REC retirement in WREGIS. As part of the 15-day changes, staff proposed that, whenever applicable, REC retirements must be demonstrated through quarterly reporting in the LRT-CBTS. In addition, the entity claiming low-CI electricity through REC retirement must be able to provide any documentation as set forth in section 95488.8(i)(B) upon request of the Executive Officer.
>
> In further response to SEVCG1_116-3b and SEVCG2_B10-3b, staff would like to clarify that intent of proposed requirements is to ensure that entity claiming low-CI electricity can unequivocally demonstrate that REC or any environmental attribute associated with the claimed electricity was retired in its behalf, specifically for the LCFS purpose. Staff is committed to working with stakeholders to implement the effective tools and efficient procedures for implementing the reporting requirements. Further, as part of the 15-day changes, staff proposed the book-and-claim accounting for low-CI or renewable electricity could span up to three quarters instead of only two quarters. Staff believes this change would allow entities sufficient time to generate and retire environmental attributes associated with low-CI electricity claimed in LCFS. Staff would also like to clarify that Lookup Table pathway for zero-CI electricity may be used for reporting electricity claimed through indirect book-and-claim accounting as long as all other reporting requirements are met.

D-6.7b. Comment: Renewable Energy Credit (REC) Retirement:

As mentioned above, 3 Phases agrees with the language in Section 95488.8(i)(1)(B)(3) regarding the requirement for REC retirement. However, 3 Phases believes clarification is needed regarding how many RECs need to be retired to achieve a zero CI score. Since the California Renewables Portfolio Standard (RPS) requires that the grid is already supplied with renewable electricity, REC retirements for the LCFS program should only be required in addition to the RPS percentage of the electricity mix. For example, if charging load over a period is 1,000 MWh and the RPS requirement for the grid is 29% renewable during that same period, the entity claiming the LCFS credits should be required to retire 710 RECs, NOT 1,000. The additional 290 RECs in that example must be separately retired by the load serving entity to meet the RPS. Requiring a retirement of 1,000 RECs specifically for the LCFS program would ignore the inherent benefits of an already-partially green electricity mix in California. (3PR1_31-5)

Agency Response: Staff would like to clarify that LCFS credits for supplying electricity are calculated based on the difference between the benchmark CI and the claimed CI of the electricity. If 1,000 MWh of electricity is claimed at zero CI under the LCFS, then 1,000 RECs would need to be retired on behalf of the LCFS to ensure that this electricity is at zero CI. The electricity being used to comply with the LCFS is not also eligible for compliance under the RPS. That is, if 1,000 MWh of electricity is used under the LCFS, then no portion of this amount may be claimed under the RPS, as the electricity used under the LCFS must be above and beyond what would otherwise be required under the RPS, or there is concern for double counting of renewable attributes.

D-6.8. ***Concerns Related to Proposed Indirect Book-and-Claim Accounting for Renewable or Low-CI Electricity***

D-6.8a. Comment: We, along with other stakeholders, have expressed concern that the RE provisions in the proposed rule could lead to significant issuance of RE charging credits without a commensurate reduction in emissions from either the electrical grid or the transportation system, compared to issuing credits at the grid average rate. California has significantly over-complied with current Renewables Portfolio Standard (RPS) requirements, which means that there is an excess of renewable energy available to in-state utilities and balancing authorities, compared to their regulatory obligations. This excess means if a utility customer switches from a standard grid-average plan to a Green Tariff plan, they will nominally be getting lower-emitting power but in reality, they could merely exchange their grid mix supply for some of the excess renewable supply, resulting in net emissions from the grid that have not changed as a result of their switch. Charging station operators could sign up for a Green Tariff plan, receive additional LCFS credits for their activity without actually reducing emissions more than if they had received credits according to the standard grid average rate. This breaks the fundamental relationship upon which the LCFS is based: market-based incentives are granted for activity which actually reduces emissions compared to the status quo. (NEXTGEN1_124-39)

Agency Response: Staff believes the proposed indirect book-and-claim framework promotes the use of renewable and low-CI electricity as a transportation fuel. Staff proposed the low-CI or renewable electricity claimed must not generate (or must retire, on behalf of the LCFS) all RPS-eligible environmental attributes to be eligible for indirect accounting in LCFS, which means that this electricity may not be claimed for compliance under the RPS. This mechanism ensures no double counting would occur for renewable electricity.

D-6.8b. Comment: Since the initial concepts were presented in 2017, Staff have clarified that Green Tariff plans must also demonstrate that they must procure renewable energy which is in addition to any required under other policy mandates. Specifically, § 95488.8 (i)(1)(B)(2) of the proposed regulation order states:

> "All electricity procured by any LSE for the purpose of claiming a lower CI must be in addition to that required for compliance with the California Renewables Portfolio Standard or, for hydrogen produced outside of California, in addition to local renewable portfolio requirements"

We urge CARB to clarify this provision to ensure that it results in a strict application of an additionality test for any renewable electricity which seeks eligibility for RE credits. Specifically:

- This provision should specify "... in addition to that required for compliance with the California Renewables Portfolio Standard, *or other renewable energy requirements...* " This will reflect the fact that other Federal, State or Local policies may require the deployment of RE and any such deployment would be subject to the same additionality concerns as relate to the RPS. Electricity used to satisfy voluntary programs or which has been credited under other market-based mechanisms should still be eligible for compliance.
- "In addition to compliance with the California Renewables Portfolio Standard" should be clarified to indicate that renewable energy in excess of that standard's requirements in a given year is not necessarily eligible for RE charging credits. To satisfy additionality, renewable electricity must have been generated by a resource which has never been used for compliance with the RPS or another renewable energy mandate. If electricity from a generator or Renewable Energy Certificates from a generator are, at some point, used to demonstrate compliance with a renewable energy mandate, this is strong evidence that the generator would have been operating whether or not LCFS credits were part of its revenue structure; it should rightly be considered part of the existing grid mix and EV charging it supports would not result in additional emissions reductions.

This functionally means that RE generators must choose whether they wish to sell in to the LCFS credit market or the broader pool of grid resources. While this limits the potential market for RE generators to some extent, we are confident that the extra revenue associated with LCFS credits, and the potential for dedicated contractual agreements, such as Power Purchase Agreements (PPAs) with charging service providers or other aggregators of charging activity using book-and-claim accounting will create a robust market for RE generation which can be dedicated to LCFS charging.

We note that the need to exclude generators which were previously used for compliance with RPS or other renewable electricity requirements is a direct result of California's significant over-compliance with its RPS (which is, in most respects, a positive development). In areas where no excess of renewable electricity above mandated requirements exists, charging on a Green Tariff or similar rate plan implies additional renewable energy must be procured. In jurisdictions where there is no excess generation of renewable energy, which may include California as RPS requirements increase, the requirement in this point could be relaxed.

- The provision should clarify that RE credits should be issued only when there is clear evidence that the charging behavior which generated those credits resulted

in real reductions in emissions, beyond what would have occurred in absence of the RE credits.

We applaud CARB and LCFS Program Staff for recognizing the need to ensure RE credits yield additional reductions compared to a business-as-usual case. **NextGen supports the inclusion of Renewable Energy charging credits, provided that they satisfy a strong test of additionality.** The clarifications described above would help develop a suitably strong test of additionality. (NEXTGEN1_124-40)

Agency Response: Staff agrees that additionality is important and has already proposed additionality checks in the existing regulation text to prevent double counting of electricity used to demonstrate compliance with the LCFS versus compliance with other environmental programs. Other fuels eligible to receive LCFS credit and associated carbon-intensity reduction strategies are not required to demonstrate that the fuel production would have happened or not happen without the existence of the LCFS. Specific requirements that the fuel volume be created solely to satisfy LCFS compliance requirements is not a requirement of the present regulation. LCFS incentives will create additional demand for low-carbon electricity, especially as the stringency of other California policies related to decreasing the carbon intensity of grid electricity increases. Crediting under the LCFS is only permitted for electricity that goes above and beyond the California's Renewable Portfolio Standard (RPS) requirement, so no additional LCFS incentive is given to electricity that matches California's RPS mandated level, and only applies to low-carbon electricity procurement that goes beyond this level. Staff proposed requirements only to prevent double counting with California RPS and did not address any future federal, state, or local renewable or low-CI mandates as staff is not aware of any such requirements that would constitute double counting. Staff is committed to review any future low-CI or renewable energy mandates and propose necessary changes to avoid any potential double counting.

D-6.8c. Comment: 2. There is a risk of double counting renewable energy when calculating electricity pathways under Section 95488.5(d) and (e). Electric grid and TOU pathways are calculated based on the energy resource mix reported to the California Energy Commission. ARB has proposed fuel pathways for EV charging and H2 production using renewable and/or low CI energy that is not collocated with the consumer. Credit generators can apply for these pathways provided the renewable electricity is supplied to the grid within a California Balancing Authority and the credit generating entity can demonstrate via contract or invoice that the renewable energy was provided for electric vehicle charging or hydrogen production. The volume of renewable energy provided directly to end users should be removed from the resource mix of renewable energy supplied to the grid prior to calculating the carbon intensity of the grid electricity. (VALERO1_69b-4a)

Agency Response: Although double counting due to adjustments in the CI of the electricity grid caused by changes in the generation mix may be possible, at this time the shift in generation mix driven by the LCFS is very small and will

have an negligible effect on the grid average CI and the base credit generation using grid average CI. If the total amount of electricity claimed under the incremental crediting provisions becomes substantial as compared to the total amount of electricity consumed for all uses in California, staff will reevaluate this decision.

D-6.9. *Deliverability of Low-CI Electricity within California Balancing Authority*

D-6.9a. Multiple Comments: *Deliverability of Low-CI Electricity within California Balancing Authority*

Comment: Powerex … suggests CARB consider broadening the area in which renewable resources can be located beyond the local California Balancing Authority.

Powerex notes that other California programs recognize renewable, zero and low-CI resources located outside of a California Balancing Authority to serve the State's load. For example, under CARB's Regulation for the Mandatory Reporting of Greenhouse Gas Reporting Regulation and the Cap-and-Trade program, out-of-state electricity that is directly delivered to California from a specified source is reported at the carbon emission factor of that specified source. Therefore, a renewable resource, such as wind and solar, that is directly delivered to California has a GHG emission factor of zero.[4]

[4] In addition, under California's Renewable Portfolio Standard ("RPS") program, eligible renewable energy resources located outside of California may qualify as Portfolio Content Category 1 so long as such energy is scheduled from the resource into a California balancing authority without substituting electricity from another source. Further, both Portfolio Category 2 (firm and shaped energy) and Portfolio Category 3 (unbundled RECs) were developed to allow for out-of-state eligible renewable energy resources to qualify for California's RPS program.

Considering that California has long recognized zero-carbon renewable resources, from a broad geographic footprint, in meeting the State's long term climate goals, Powerex suggests CARB consider removing the restriction in proposed section 95488.8(i)(1)(A) that renewable electricity must be supplied to the grid within a California Balancing Authority. CARB should consider developing rules so that the electricity from renewable resources, located outside a California Balancing Authority, which is supplied to ZEV fueling stations, may be included in the carbon intensity determination for LCFS purposes. (POWEREX1_82-2)

Comment: Allow for Imported Low-CI Electricity

AMP suggests ARB reconsider its stance on limiting renewable electricity supply to within the same California Balancing Authority. In fact, AMP believes ARB should be looking for ways to allow for imported sources of low-CI electricity to participate in the LCFS program.

In Sec 95488.8(i)1(A), ARB states "The renewable electricity must be supplied to the grid within a California Balancing Authority (or local balancing authority for hydrogen produced outside of California)".

According to the California Energy Commission, in 2016, 32% of California Power Mix (CA-Mix) was imported. Barring imported low-CI electricity from generating LCFS credits denies potential low-CI electricity generators an incentive that could be used to help clean up almost a third of the CA-Mix. If ARB does not incentivize low-CI electricity generation on imported electricity, it will not be addressing almost a third of the CA-mix. AMP believes that ARB is missing an opportunity to support potential low-CI electricity suppliers and that ARB should re-consider allowing imported low-CI electricity to earn credits in the LCFS program. (AMP1_86-7)

> **Agency Response:** Staff appreciates the commenters' insights and recommendations. As part of the 15-day changes, staff proposed that low-CI electricity is eligible for indirect accounting as long as it meets the interconnection or scheduling/delivery requirements of California Public Utilities Code section 399.16, subdivision (b)(1). Staff believes the proposed change would provide sufficient flexibility for supplying low-CI electricity as transportation fuel.

D-6.9b. Comment: We do not oppose a requirement that the renewable electricity must be supplied to the grid within a California Balancing Authority. That said, we urge the Board to apply the same deliverability principles to all forms of alternative fuel. (CBEA1_128-4)

> **Agency Response:** The LCFS program allows significant flexibility to other forms of alternative fuels in terms of deliverability as alternative fuels from all parts of the world are delivered to California and reported in LCFS. For example, renewable natural gas generated from a landfill in New York, or ethanol produced in Brazil, or renewable diesel produced in Singapore are delivered to California and generates credits or deficits when reported in LCFS. Also, as part of the 15-day changes, staff proposed that low-CI electricity is eligible for indirect accounting as long as it meets the interconnection or scheduling/delivery requirements of California Public Utilities Code section 399.16, subdivision (b)(1).

D-6-10. *Energy Economy Ratio Updates*

D-6.10a. Multiple Comments: *Proposed Update to the EER for Heavy-Duty Electric Bus and Truck*

Comment: There needs to be accurate accounting of the relative efficiencies of all technologies in the LCFS program. The Energy Economy Ratio (EER) assigned to each technology have a significant impact on the credits generated within the program, as well as competition amongst the technologies for market share. Despite these implications, Staff is only proposing to amend the EER values for EV applications while all other fuel application EERs remain the same. Furthermore, Staff is proposing to eliminate the EER classification for EV buses and trucks and classify all EV on road fuel under a single EER. Under this assumption, the EER for electric heavy-duty trucks double when there has been no substantive truck data to support this. There are no electric heavy-duty trucks in service today. Truck and transit duty cycles are dissimilar with different weights, driving patterns, and operational loads (lighting, comfort features,

doors, etc.). They should not be grouped into one category with the same EER unless they have been thoroughly tested to support the assigned EERs.

The studies to determine EER for electric transit vehicles are inadequate. The use of chassis dynamometer data for EVs neglects the substantial energy demands associated with heating, ventilation, and cooling systems. Internal combustion engines generate significant amounts of waste heat that are typically used to supplement HVAC heating demands. By contrast, EVs must typically supply all the heat demand through heat pumps and resistance heaters. These demands can be substantial, relative to the average propulsion energy demand of the vehicle.

Additionally, the Altoona test data used to calculate EERs for electric buses does not include charger efficiency losses. Based on charging data included in the Altoona reports, charging efficiencies could range from 75-90%. Because neither CA-GREET 2.0 or the draft CA-GREET 3.0 model include impacts of charging efficiencies in the calculated carbon intensity for electricity, the charging efficiencies must be incorporated into the EER values for these vehicles. It does not appear that ARB's analysis has appropriately accounted for the impacts of charging efficiency.

The study cited to support the proposed EER amendment is flawed and does not reflect the true efficiency of EV vehicles on road today. Staff is using impractical assumptions with respect to the future deployment of EV fleets at low speed duty cycles. These broad assumptions ignore the driving cycles of EVs on road-today and allow less efficient EVs to benefit from research conducted only on the most favorable models of the technology. This approach of modeling EERs or CIs using the most advanced technology has not been allowed in modeling CIs or EERs of other fuel applications such as NGVs. In fact the EER value for NGVs and the fossil CNG lookup value were determined using the most conservative assumptions and data available. Conservative data should also be used of EVs until there is enough accurate data available.

As previously stated, the EER values have a significant impact on the credits generated in the program which emphasizes the need for Staff to update all fuel application EERs at the same time, including the baseline for gasoline and diesel. If Staff does not provide the same evaluations for all technologies to do this in the final draft amendments, it will create a competitive advantage for EVs (doubling the amount of credits generated by EV trucks) which is not consistent with the fuel neutrality premise of the LCFS program. This is especially the case when we believe newer NGV technology is providing a better EER value than ARB is currently applying to our industry. (SCG1_75-6)

Comment: Our examination of the EER values developed in Appendix H showed that the methodology adopted by ARB to develop the EER ignored some aspects of engine efficiency trends with load and speed, and also did not consider the differences between dynamometer test procedure and real-world operation. In addition, the effects of ambient temperature were not discussed or included in the computation of EER. Chassis dynamometer ("dyno") tests are conducted with all accessories off and at an ambient temperature of 70 to 75 F, which are conditions where EER for electric vehicles

may be the highest. Because these conditions may be experienced for only short periods of time in much of California, EER values developed from dyno test data do not reflect real world conditions for much of the time such vehicles will be operating. The discussion below on engineering considerations provides a foundation for the critique of specific EER values in the following sections. (GROWTHENERGY1_B4-75)

Comment: ARB has derived data for electric bus EER values from tests conducted at the Altoona bus center, and the data suffers from many of the same issues raised for the propane bus EER analysis. As noted, the HVAC system is turned off during the tests. The Altoona bus tests showed a 5.4 EER for an electric bus relative to a diesel bus over the CBD cycle which has an average speed of 12.7 mph. As noted in Section 4, the track tests do not use "realistic" cycles and even comparisons between similar vehicles of different fuel types can be erroneous if the powertrain efficiency responds differentially to load.

A more valid comparison is obtained from the NREL study[3] comparing electric buses to CNG buses in the San Gabriel and Pomona Valley region where data was collected from in-service buses where the HVAC was functioning. This study is referenced by ARB but oddly, it shows data attributed to the NREL study that differ in fuel consumption by a factor of 2 for CNG buses to what is shown in the NREL study.

[3] NREL, Foothill Transit Battery Electric Bus Demonstration Results, Technical Report NREL/TP-5400-65274, January 2016

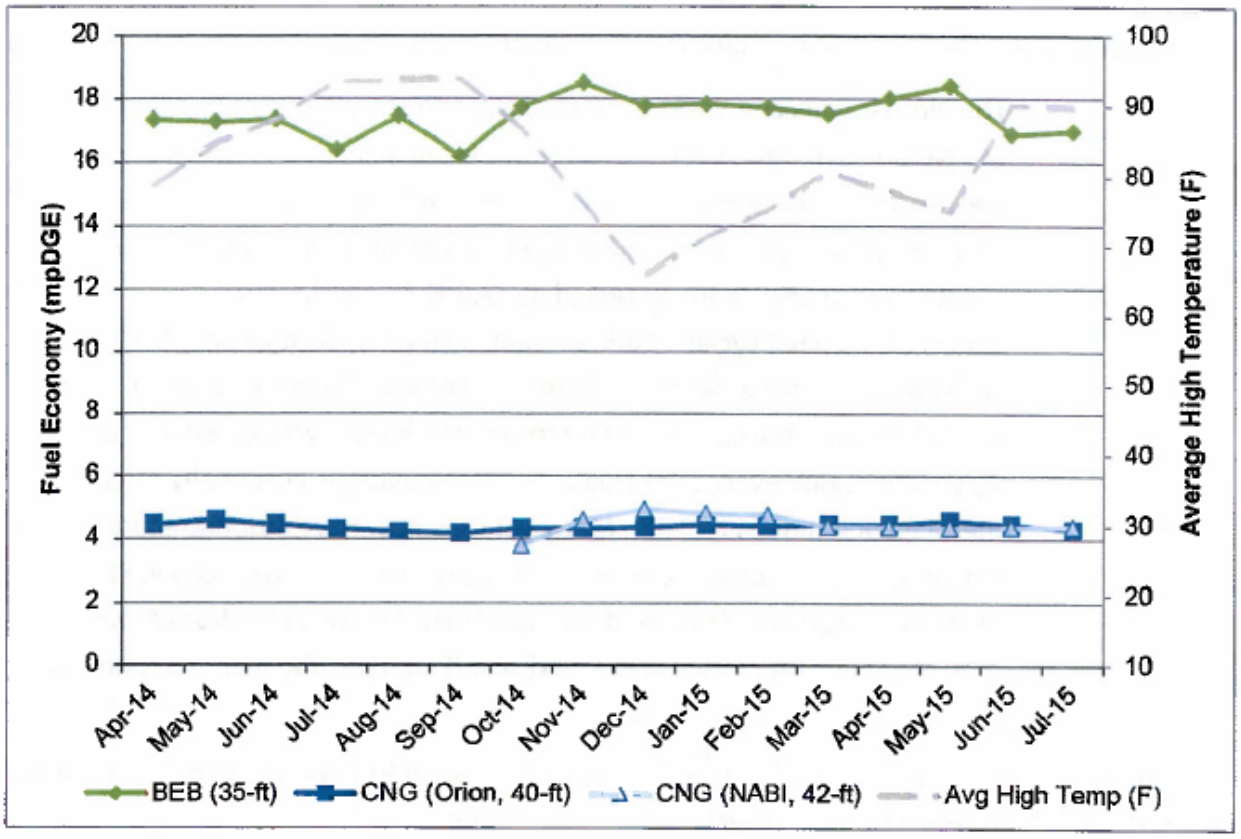


Figure 3: Fuel economy of Electric buses and CNG buses operated by Foothills Transit

The CNG bus fuel economy is shown as 2.1 mpg (diesel equivalent) in Appendix H but the NREL report lists the CNG bus fuel economy as 4.51 mpg diesel equivalent. The electric bus fuel economy is reported in both studies as 17.5 mpg so that the computed EER differs by more than a factor of 2. Our computation of EER for the electric bus from NREL data shows an EER of 3.29 relative to a diesel bus assuming that the diesel is 15% more efficient than a CNG bus. The NREL report indicates that average speed was 8.42 mph with over 50% of time at idle as evidenced by the average speed excluding idle time of 17.66 mph. Figure 3 shows the seasonal variations in fuel economy which are small as the valley has a mild climate but the dip in electric bus efficiency is significant during the warmer months and the electric bus efficiency dips as low as 16 mpg while the CNG bus efficiency declines to 4.1 mpg The EER also does not account for the fact that the CNG buses are larger than the electric buses (40 to 42 ft. long vs. 35 ft for the electric bus). At more extreme climates and especially at colder temperatures, we anticipate that the EER should be close to 3.

Results for the Drayage truck and the parcel delivery van are based on comparisons of more similar vehicles EV and diesel tested on the dynamometer. The issue of HVAC use is till pertinent but the energy consumption by the system on a truck is a smaller factor than on a bus. However, two other significant issues not considered by ARB affect the EER

- The electric vans and drayage trucks have the same GVW as the diesel trucks but would have significantly lower payload capacity due to the battery weight. The parcel vans may be volume constrained rather than load constrained in many cases. The drayage trucks however were obviously load constrained as they were all tested at 72,000 lb. GVW.
- On very low speed cycles under 15 mph, a large amount of time (>50%) is spent at idle. Since a diesel consumes fuel at idle but the EV consumes very little electricity, the EER should increase with lower cycle speed as shown in Appendix H. However, California anti-idle regulations potentially reduce diesel engine time in real life. Many vehicles now have automated idle shut-off after 1 minute of idling. Hence, the steep rise in electric vehicle EER is likely inaccurate for more modern diesel vehicles with idle shut-off which may become a requirement in California. (Extended idle over 5 minutes is already banned in California).

Based on these factors, we expect that Electric truck EER even at low speed will be in the same range of 3 to 3.5 observed for electric vehicles of other types. (GROWTHENERGY1_B4-83)

Comment:

- The EER for electric buses operating at urban speeds appears to be significantly overstated and appears to partly based on a misreading of NREL data.
- The EER for commercial electric trucks compares energy efficiency at the same gross weight which ignores the loss of payload due to the weight of the battery (which can be very significant). In addition, diesel engines operating at very low speed cycles which involve extensive idle will have significant efficiency improvement with idle shutoff, a feature that will have significant market penetration due to EPA GHG regulations on trucks. (GROWTHENERGY1_B4-90)

Comment:

EER Summary

Vehicle Type	EER recommended by ARB	Suggested Correction
Electric Bus	4.8 at urban speed	About 3 as an all-season average
Parcel and Drayage Trucks	4 to 5.5	Payload loss, seasonal effects and diesel idle shutoff not accounted for.

(GROWTHENERGY1_B4-99)

Comment: What is the definition of Energy Economy Ratio (EER) in light of the new EER value for Heavy Duty BEV?

In Table 45, ARB proposes to change the EER Values for all Electric Vehicles to 5.0.

In section 95481 (39), ARB defines “Energy Economy Ratio (EER)” means the dimensionless value that represents the efficiency of a fuel as used in a powertrain as compared to a reference fuel used in the same powertrain. EERs are often a comparison of miles per gasoline gallon equivalent (mpge) between two fuels. EERs for fixed guideway systems are based on MJ/number of passenger-miles.

AMP recognizes ARB’s proposal to change the EER of heavy duty electric vehicles to 5.0. However, AMP asks for ARB’s clarification in how the intent of EER is evolving to qualify the EER of a heavy duty electric vehicle as 5?

AMP believes that 2.7 was an appropriate EER for heavy duty electric trucks. For example: the Tesla Semi, the heavy-duty electric vehicle that has gained the most media coverage, has a stated fuel efficiency target of 2 kwh per mile. Assuming 3,412 btu per kwh, 85% charger efficiency (from Argonne National Labs AFLEET Tool), 6.3 miles per diesel gallon (DGE) of a heavy-duty combination long-haul diesel truck (also from AFLEET), and 129,500 btu per DGE: the Tesla Semi has an EER of 2.56 to the diesel truck it will be replacing. Also, Argonne National Labs uses a ratio analogous to EER in its AFLEET Tool of 2.55 for heavy duty electric vehicles. (AMP1_86-6)

Comment: Ambient temperature affects the energy consumption in two ways – first by changing the energy consumption of the drivetrain and second, by requiring the use of air-conditioning or heating. As noted, these factors are not reflected in the standard dyno tests which are conducted at ambient temperatures of 70° to 75° F without the HVAC system being on.

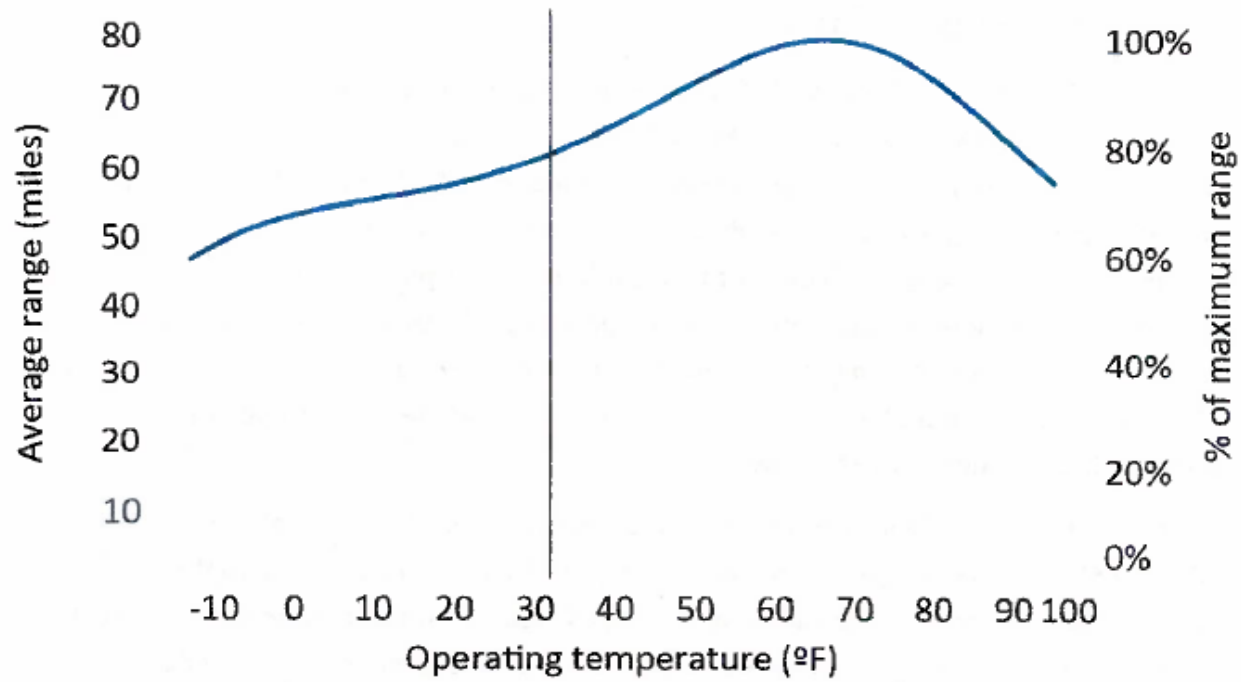


Figure 1: Average range of the Nissan Leaf as a function of Ambient Temperature[1]

[1] Data from Fleet Carma as reported on the Union of Concerned Scientists website

At cold ambient temperatures below 10° F, fuel economy of internal combustion engines is decreased significantly due to the cold start and the energy needed to heat up the engine and transmission to operating temperature but the penalty is largely restricted to the warm-up period. Hence, the penalty averaged over a long trip becomes small. On an EV, battery internal losses and self-discharge increase with decreasing ambient temperatures and the energy loss is internal to the battery. In addition, the requirement for heating the cabin further deteriorates the vehicle EER. The combined loss results in loss of range, which is significant. An example of the loss of range with changes in ambient temperature for the Nissan Leaf EV is shown in Figure 1. As can be seen from the figure, battery range is maximum at 70° F (the typical dyne test temperature) and drops at both higher and lower temperature. At both 100° F and at 32° F, the range is 78% of the range at 70° F. Internal combustion engine powered cars have similar losses in fuel economy in summer but lower losses in winter, so that the reduction in EER of electric personal vehicles is potentially modest. However, in buses and commercial vehicles, the reduction in EER at colder temperatures may be quite large due to the high heating and ventilation load. We anticipate that the EER of electric vehicles could decline by 10 to 15% for passenger cars and cargo trucks, and by 25 to 30% for buses in winter (50° F) and summer (>90° F) relative to the EER estimated from tests conducted at 70° F with the accessories shut off. (GROWTHENERGY1_B4-75e)

Agency Response: Staff agrees with the commenter that accurate accounting of the relative efficiencies of all technologies in the LCFS program is important. To develop EER values, staff relies on the best data based on in-use and

laboratory test studies of production vehicles that was available at the time. Staff is committed to re-evaluating EER values as and when more relevant data is available. In Appendix H of the ISOR posted on March 6, 2018, staff analyzed the EER values for heavy-duty electric vehicles relative to conventional diesel vehicles. Given the values for heavy-duty electric bus and truck was relatively close, staff proposed to use an average EER to simplify the reporting in the LCFS. Other transport applications using alternative fuels may also cover a wide variety of technology and vehicles, however, for the ease of reporting and to avoid cumbersome verification of application type LCFS assigns EER values to broader application type, such as heavy-duty electric bus, and not subtype of subclass of vehicle within that application type.

Staff disagrees with the commenter that the studies to determine EER for electric transit vehicles are inadequate. As mentioned, staff relied upon the best data available for commercially-available vehicles, including chassis dynamometer studies as well as in-use test studies. The results from both type of studies were found to be consistent in terms of fuel economies. Therefore, the EERs developed by staff were based on real world testing as well. Staff commits to re-evaluate and update the EER values as more fuel efficiency studies become available.

Staff agrees that charging efficiency is not accounted in the EER analysis as it is not covered under EER definitions – "EER means the dimensionless value that represents the efficiency of a fuel as used in a powertrain as compared to a reference fuel used in the same powertrain." Similarly, fueling losses for other fuel applications like CNG, Gasoline, Hydrogen, etc. are also not currently accounted for in the EER values or in the life cycle analysis for CI determination.

In response to AMP1_86-6, staff provides a detailed methodology employed to estimate the proposed EER value for heavy-duty bus and truck in Appendix H of the ISOR. Staff encourages commenter to review the Appendix H in which staff relied on the best data available to staff based on in-use and laboratory test studies of production vehicles at the time of estimating the proposed EER values.

In response to GROWTHENERGY1_B4-75e, the methodology used for EER development under the LCFS program is solely a comparison of vehicle fuel efficiencies under the same duty cycles. When developing EERs for all fuel-vehicle combinations, staff included all data from various in-use and laboratory studies. The in-use tests results compares the vehicle operations in actual driving conditions, which account for the impact of ambient temperature. Staff commits to re-evaluate and update the EER values as more relevant data become available.

D-6.10b. Multiple Comments: ***Proposed EER Value for Electric Transportation Refrigeration Units***

Comment: ARB acknowledges that the data from Transport Refrigeration units (TRU) is sparse and has estimated the EER from a single fleet using a sample of 4 diesel TRU units. Appendix H mentions that electricity use was obtained from one of the units but it is unclear if diesel and electricity use were obtained from the same unit. The EER developed uses the four diesel unit data and the single data point for electricity consumption. However, the diesel data showed vary large variance in the TRU diesel fuel consumption with one unit at 0.40 gal/hr, the second at 0.81 gal/hr, the third at 1.31 gal/hr and the fourth at 1.57 gal/hr, which is a 392% variance between units ostensibly of the same size. This would suggest that the refrigeration loads were very different between the units, and if electricity consumption was measured with diesel consumption on the same unit, it would be important to use a consistent set of data to derive the EER value. It is also unclear why the median electricity consumption value rather than the mean was selected to derive the EER.

The computed EER value of 3.4 may be a reasonable or somewhat optimistic value, as the efficiency of a diesel engine in cyclic operation is typically 25 to 30 percent, while the efficiency of an electric motor/ controller driving the compressor of the TRU can be in the 80% to 85% range which would suggest EER values in the 2.7 to 3.4 range. (GROWTHENERGY1_B4-81)

Comment: The EER for Transport Refrigeration Units is derived from a small and excessively variable set of data. It is unclear if the comparison between electricity consumption and diesel consumption is based on the same duty cycle. (GROWTHENERGY1_B4-88)

Comment:

EER Summary

Vehicle Type	EER recommended by ARB	Suggested Correction
Electric TRU	3.4	ARB data too variable for conclusion

(GROWTHENERGY1_B4-97)

Comment: AEM recommends the establishment of a second EER for advanced technology electric transport refrigeration units (advanced eTRU) with Executive Officer approval. Advanced eTRU deliver temperature-controlled product with greater energy efficiency and zero-emissions throughout the entire delivery cycle and as such displace more diesel fuel per unit of electricity than conventional electric standby eTRU. Inherent breakthroughs in refrigeration system efficiency are achieved to enable battery electric TRUs to meet rigorous application requirements to provide in-route cooling solely from

energy stored in a battery. Advanced eTRU should be rewarded with a higher EER for the greater displacement of diesel fuel.

AEM pledges to make data available to CARB staff to quantity and justify a higher EER than 3.4 so Executive Officer approval can be given for a higher EER for advanced eTRU. (AEM1_54-4)

> **Agency Response:** As stated in the Appendix H, the data available for the development of EER value for electric Transportation Refrigeration Units (eTRUs) is limited. Staff recommended a conservative value based on the best available data. Staff commits to re-evaluate and update the eTRU EER value as more relevant studies such as those mentioned in Appendix H of the ISOR become available.
>
> In response to AEM1_54-4, staff appreciates the commenter's suggestion to create multiple EER for the same transportation application. However, the LCFS program provides an estimated average EER value for each transportation application classified in LCFS, such as eTRU, and does not estimate EERs specific to subtype or subclass of technology within that application, such as advanced eTRU. Further, as stated in Appendix H of the ISOR, the proposed EER value is based on the best available data to staff at that time but staff is committed to re-evaluate and update the proposed EER values in future rulemaking if more relevant data is available.

D-6.10c. Multiple Comments: ***Proposed EER for Electric Motorcycles***

Comment: ARB has derived the EER for electric motorcycles based on a sample of electric motorcycles tested by the EPA on the UDDS cycle on the dyno, and comparing the energy use to gasoline motorcycles with similar rated power. However, the UDDS is a very slow speed cycle with gentle accelerations and multiple stops. Motorcycles have very high power-to-weight ratios relative to cars and trucks, and the UDDS is not likely to represent the driving cycle for most motorcycle owners. (ARB should also distinguish between on-road motorcycles versus children's electric motorcycles which do not provide any energy benefit) In addition, gasoline motorcycle engines are designed for high specific output and are quite inefficient at the low speeds in the UDDS. The EER values of 8 to 10 found in the sample comparison are not applicable, and ARB has recognized this and suggested an EER of 4.4. However, no basis is provided for the staff multiplying the UDDS value of EER by 0.5 to obtain the 4.4 value. One option may be to use the US06 cycle for testing both electric and gasoline motorcycles as this would represent a more aggressive and well-developed cycle but not derived from motorcycle specific driving patterns. Otherwise, driving cycle data from instrumented motorcycles will need to be collected and a test procedure developed to characterize motorcycle EER.

Electric motorcycle efficiency can also be deduced from the battery capacity and claimed range from the motorcycle manufacturer websites. As an example, Zero motorcycles claims a city/highway combined range of 108 miles with a 13 kWh battery and a range of 138 miles with a 16.6 kWh battery for its Zero S model. Assuming that 90% of battery capacity is available for use, the energy consumption is 0.11 kWh/mi at the battery and

0.13 kWh/mi at the plug assuming battery charger efficiency and battery storage loss combined of 85%. The motorcycle has a motor rated at 60HP, which is comparable to gasoline motorcycles with a 650cc to 750cc engine. Data from the motorcycle fuel economy guide[2] shows ratings of about 60 to 70 mpg for many such vehicles (although there is a lot of variability) which indicates a potential EER of about 3.5. A more comprehensive analysis is required to establish a more accurate EER but we anticipate that EER values of about 3.5 may be more realistic than the 4.4 value suggested by ARB as we expect similar EER values to those derived for electric cars.

[2] www.totalmoto rcycle.com/ MotorcycleFue1Econ omyGuide/ 2016b

(GROWTHENERGY1_B4-82)

Comment: The EER for electric motorcycles appears to have been derived arbitrarily. Data from motorcycle websites suggest lower values than those developed by ARB but more research is required. (GROWTHENERGY1_B4-89)

Comment:

EER Summary

Vehicle Type	EER recommended by ARB	Suggested Correction
Electric Motorcycles	4.4	Probably closer to 3.5, need data

(GROWTHENERGY1_B4-98)

> **Agency Response:** As stated in Appendix H of the ISOR, staff acknowledges that a truly representative EER would be based on data collected over multiple drive cycles representing real world operating conditions. However, staff disagrees that the EER values for electric motorcycles are derived arbitrarily. The EER analysis is based on the best data available to staff. To account for the possible difference between the efficiency achieved in the test cycle as compared to that likely to be achieved in real world usage, staff discounted the initial EERs by a factor of 0.5. This conservative EER value will incentivize the emission reduction from the use of electric motorcycles until a more comprehensive data set of motorcycle efficiencies under various operating conditions can be collected and analyzed. Staff commits to re-evaluate and update the e-motorcycle EER value as more fuel efficiency studies become available.

D-6.10d. *Conventional Gasoline and Diesel Vehicle Engines*

Comment: Gasoline and diesel vehicles are the baseline for comparison for developing the EER values of alternative fuel vehicles. In modern vehicles the spark ignition (gasoline) engine has a peak efficiency of 35 to 36 percent but some more recent designs being introduced in cars and light trucks have efficiencies approaching

40%. Light duty diesels have a peak efficiency of about 41 to 42 percent but do not have near term prospects for improving significantly.

In a heavy-duty vehicle, diesel engines are more efficient with peak efficiency of 43 to 44%. However, the peak efficiencies are realized at high loads and the efficiency of both diesel and gasoline engines decline at low loads and is zero at idle by definition. The diesel's efficiency declines less than that of a s.i. engine with load reduction so that its relative efficiency over a gasoline engine improves at light load. (GROWTHENERGY1_B4-75a)

> **Agency Response:** Please refer to the response to GROWTHENERGY1_B4-25b in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

D-6.10e. *CNG and Propane Engines*

Comment: Natural gas and propane are used primarily in spark ignition (s.i.) engines, but the type of s.i. engine differs between those used in light and light heavy vehicles up to about 14,000 lb. GVW. In these lighter vehicles, propane and natural gas engines are simple conversions of gasoline engines, with only the addition of a different fuel system. Efficiency is generally unaffected, implying a EER of 1.0. However, the tanks used for propane and CNG fuel are quite heavy and a CNG tank capable of providing over 200 miles range can weigh over 250 lbs. which is a significant weight increase. On a 4000 lb. gasoline vehicle, the addition of CNG tanks can cause fuel economy to decrease by 3 to 5 percent so that the EER will decline to 0.95 to 0.97. The lower power of the CNG engine further compromises the EER due to axle ratio and gear shift adjustments that must be made to restore performance and the net EER can decline to 0.9.

CNG spark ignition engines used in heavy trucks over 18,000 lb. GVW typically use a modified diesel engine so that they are highly turbocharged and offer better efficiency than a simple gasoline engine conversion but are still subject to the same trends with load and speed. While on a highly loaded duty cycle, the EER of a CNG can be as high as 0.9 relative to a diesel, this value declines due to the diesel's improved efficiency at lighter loads relative to an s.i. engine. In addition, the weight of the fuel tanks for the CNG fuel also reduces the vehicle efficiency at similar payload. (GROWTHENERGY1_B4-75b)

> **Agency Response:** Please refer to the response to GROWTHENERGY1_B4-25c in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

D-6.10f. *Electric Drivetrain and Battery Losses*

Comment: Comparison of electric drivetrain efficiency to gasoline or diesel efficiency is more difficult due to the completely different efficiency characteristics of an electric

motor relative to an internal combustion engine. Typically, an electric motor is most efficient at mid load/ low speed operation but becomes less efficient at high loads and very light loads. At “idle”, and electric motor uses very little power (mostly in the controller). A typical electric motor/ controller's peak efficiency can be as high as 92 to 93% but the average efficiency in most light vehicular duty cycles is in the 80 to 85% range. In addition, the battery has internal energy loss during both charging and releasing energy so that the battery plus drivetrain efficiency is in the 75 to 80% range. Unlike the trend for internal combustion engines, system efficiency declines with higher loads so that on heavy trucks, the net efficiency on a highly loaded cycle can be significantly lower than the net efficiency for light vehicles.

The weight of the battery is also an important consideration in the determining the vehicle EER. In light vehicles with a range of 150 to 250 miles, the battery system weight ranges from 500 to 1000 lbs. while on a heavy truck, battery weight is 15% to 20% of the gross vehicle weight if the range is 150 to 200 miles. This has very significant impact on the EER of the vehicle and the EER can only be defined in the context of specific vehicle range and battery weight. (GROWTHENERGY1_B4-75c)

> **Agency Response:** Please refer to the response to GROWTHENERGY1_B4-25d in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

D-6.10g. ***Impact of Accessory Loads***

Comment: As noted, accessory loads are not switched on during dynamometer testing and their impact on the EER varies by vehicle type. Incorporation of accessory loads increases the load on the engine, or in the case of an EV, the battery. Increasing the load on an engine makes it more efficient while increased loads on the battery make it less efficient so that this affects the EER even if the accessory loads are identical. Accessory loads are particularly important in buses where the HVAC system accounts for as much as 40% of total fuel use in a transit bus in summer. These loads have a more modest effect on light duty vehicle fuel consumption.

In winter, diesel and gasoline engines use waste heat for providing passenger cabin heating but this is not possible in an EV where there is very little waste heat available. As a result, battery energy must be used and the resulting energy consumption substantially affects the EER. The reduction in EER can be very significant as many EVs use resistance heating for low cost, but this very inefficient. (GROWTHENERGY1_B4-75d)

> **Agency Response:** Please refer to the response to GROWTHENERGY1_B4-25e in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

D-6.10h. ***Summary of Suggested EER Changes***

Comment: As summarized on page 13 of Appendix B, numerous EERs used under the LCFS should be adjusted downward to more accurately reflect the evidence. (Appendix B at 13.) (GROWTHENERGY1_B4-25j)

> **Agency Response:** Please refer to the following responses in this chapter: Responses W-4 as it responds to GROWTHENERGY1_B4-92, D-2.3c as it responds to GROWTHENERGY1_B4-96, D-6.10b as it responds to GROWTHENERGY1_B4-97, D-6.10c as it responds to GROWTHENERGY1_B4-98, and D-6.10a as it responds to GROWTHENERGY1_B4-99. These Growth Energy comments refer to the EER summary mentioned in the above comment.

D-6.11. ***Adding New Transportation Applications***

D-6.11a. Multiple Comments: ***Request to Add New Transportation Applications***

Comment: Maersk Line and our sister company APM Terminals appreciate this opportunity to comment on the Proposed Amendments to the Low Carbon Fuel Standard (LCFS) Regulation. We request that these amendments include opt-in credit generating pathways for the following:

1. Ocean-going vessels (OGV) using shore power from the shore-side electrical grid in lieu of operating auxiliary engines while at berth.
2. Use of alternative or renewable fuels by OGV at berth or in the California fuel zone, and consideration of mechanisms for credit for vessel energy efficiency projects.
3. Electrification (full or partial) of Cargo Handing Equipment (CHE) or use of alternative fuels that provide a greenhouse gas benefit as compared to traditional petroleum-based diesel.

We understand that these pathways would be voluntary measures. Providing such pathways would provide the following benefits:

- Co-benefits of all three options listed would include reduction of toxic air emissions such as NOx, SOx, and Diesel PM, and in some cases CO and other toxics.
- A LCFS credit pathway would encourage accelerated or surplus compliance in programs intended to reduce toxic emissions.
- Such a pathway would provide a strong incentive to use low-carbon pathways to comply with other California regulations. For example, such LCFS credits could encourage investments to enable the use of shore-side electricity rather than stack gas treatment systems to comply with the California At Berth Regulation. While stack gas treatment systems remove toxics as required by this regulation, use of these systems actually increases CO_2 emissions vs. the vessel's auxiliary

engines alone. Availability of LCFS credits would influence such investment decisions in favor of the lower CO_2 approach. (MAERSK1_62-1)

Comment: On behalf of the member companies of the Pacific Merchant Shipping Association (PMSA), we ask that the California Air Resources Board (CARB) expand the list of categories for eligibility of the Low Carbon Fuel Standard (LCFS) funding through the Energy Economy Ratios (EER) program as opt-in credit generating opportunities. PMSA is a nonprofit association of owners and operators of marine terminals and US- and foreign-flagged vessels operating throughout the world who service California's trade demands through California's commercial ports. PMSA requests that the following programs and activities at California's seaports be included as candidates for rebate funding through this program:

1. Ocean going vessel use of shore power – whereby vessels shut down their diesel powered auxiliary generators while secured and stationary in port, and plug into the grid to provide power to the vessel.
2. Cargo Handling Equipment (CHE) – whereby electrification or alternative fuels, which provide a greenhouse gas benefit as compared to traditional petroleum-based diesel fuel, are used to power cargo handling equipment.
3. Use of LNG or other or alternative fuels, which provide a greenhouse gas benefit as compared to traditional petroleum-based marine distillate fuels, replace traditional fuels; while underway and while secured and stationary in port.

The opportunity to opt-in for credit generating opportunities in these categories will create meaningful incentives for ocean carriers and terminals to use low carbon-intensive options that will reduce greenhouse gases. In addition, by creating opt-in credit generating opportunities, CARB will also support its existing regulatory programs that seek to reduce criteria and toxic pollutants from these source categories. (PMSA1_84-1)

Agency Response: Staff appreciates the commenters' support to allow Cargo Handling Equipment (eCHE) and electric shore power supplied to Ocean-going Vessels at-berth (eOGV) as opt-in categories in the LCFS program. As part of the 15-day changes, staff proposed to allow eCHE and eOGV to opt in for reporting and generating credits in the program.

In response to comment PMSA1_84-1, staff proposed EER values only for electricity used as an alternative fuel for cargo handling equipment and for auxiliary power for ocean-going vessels at-berth. However, other alternative fuel and transportation application combination, including use of LNG or other alternative fuels at ports, can be reported for generating credits in LCFS using a certified EER-adjusted CI. Please see staff's response D-6.1f in this chapter.

D-6.11b. ***EERs for New Transportation Applications***

Comment: Table 4 does not contain an Energy Economy Ratio (EER) for "other mobile freight and goods movement equipment". This value is necessary to calculate the credit generation for these sources. (VALERO1_69b-9b)

> **Agency Response:** As part of 15-day changes, staff proposed to add an EER value of 3.4 for eTRU, 2.7 for eCHE, and 2.6 for eOGV in Table 5, *"Table 5. EER Values for Fuels Used in Light- and Medium-Duty, and Heavy-Duty."*

D-6.12. ***Clarification for the Proposed New Transportation Applications***

D-6.12a. Comment: Sources included in "Other mobile freight and goods movement equipment". Is the cargo handling equipment identified in the California Sustainable Freight Action Plan the intended equipment to be included in the LCFS program? This includes trucks, locomotives, transport refrigeration units, cargo equipment, commercial harbor craft, and airport ground service equipment. (VALERO1_69b-9a)

> **Agency Response:** As part of the 15-day changes, staff proposed to allow new electric transportation applications to opt in and generate credits in the LCFS. These applications are electric Transportation Refrigeration Units (eTRU), electric Cargo Handling Equipments (eCHE), and electric power supplied to Ocean-going Vessels at-berth. The definitions for eTRU, eCHE, and eOGV are provided in section 95481.

D-6.12b. Comment: *SMUD supports consistency of the scheme for credit generation for eTRUs with other electrification applications as much as possible.* However, because eTRU requires capital investment in substantial infrastructure, the credits should not be assigned to a default party, as with the current forklift rule. Instead, SMUD supports assigning the first right to generate credits to the entity that makes the investment. That party would likely be either the eTRU capable facility owner or the EDU. (SMUD1_85-7)

> **Agency Response:** Staff proposed, for the purposes of credit generation, the electricity supplied for eligible transportation applications must be reported per fueling supply equipment (FSE). FSE is basically an equipment or a device that supplies electricity and can also measure the quantity of dispensed electricity for reporting. Each FSE is required to be registered in the LCFS Reporting Tool and Credit Banking and Transfer System (LRT-CBTS) prior to reporting. The FSE registration requirements are intended to improve the quality of reported data and help prevent potential double counting of fuel quantities dispensed in California.
>
> For reporting of electricity supplied to electric Transportation Refrigeration Units (eTRU) each eTRU must be registered as a FSE. As part of the 15-day changes, staff proposed to designate the owner of the FSE as the default credit generator for eTRU. The proposed change is consistent with other electricity applications where the FSE owners are the default credit generator as they are the ones supplying electricity as fuel.

Nevertheless, LCFS provides the flexibility to the FSE owner to designate any other entity on its behalf to be the credit generator, if it chooses not to participate in the program. Staff believes this flexibility would allow the industry stakeholders to work with each to optimize the incentives provided by the LCFS program to promote of electricity as a low carbon transportation fuel.

D-6.12c. Comment: c) *§95483(c), Fuel Reporting Entity, For Electricity Used as a Transportation Fuel* – We recommend that CARB provide and update a list that includes the electric vehicles (e.g. electric motorcycles, ground support vehicles, etc.) that are covered by the regulation and that would be eligible to generate LCFS credits. (PGE1_120-16)

Agency Response: Staff proposed to add new electric transportation applications that would be eligible for crediting in LCFS. This includes on-road electric motorcycle, Electric Transport Refrigeration Unit (eTRU), Electric Cargo Handling Equipment (eCHE), and Electric power for Ocean-going Vessel at-berth (eOGV). The definition of Electric Vehicle, eCHE, eOGV, eTRU, and Yard Trucks includes which equipments are eligible for reporting and generating credits for the respective application.

D-6.13. Multiple Comments: ***Proposed Quarterly Reporting of Daily Average EV Charging Rate for Calculation of Base Credits***

Comment: This letter also points out APU's and RPU's concern over a new reporting requirement in the Proposed Amendments for the purpose of base credit calculation.

…

The Proposed Amendment requires the Electrical Distribution Entity to "provide the (Board's) Executive Officer Daily Average EV Electricity Use data for the calculation of credits for non-metered residential charging from the prior year. The Executive Officer shall use the method set forth in subsection 95486.1(c)(1),[6] to calculate any (base) credits generated for the prior year" .[7]

[6] Proposed Amendments to the Low Carbon Fuel Standard Regulation (March 6, 2018), Subsection 95486.1(c)(1) Generating and Calculating Credits and Deficits Using Fuel Pathways – Base Credits for EDUs.

[7] Proposed Amendments to the Low Carbon Fuel Standard Regulation (March 6, 2018), Subsection 95491(d)(3)(A)1. Specific Quarterly Reporting Parameters for Electricity used as a Transportation Fuel – For Non-Metered Residential EV Charging.

APU and RPU have only a handful of customers that have chosen to meter their EVs separately (sub-metered). While each utility is able to provide this data, the size of the dataset collected would not be a representative sample of the total non-metered residential EV charging population throughout the utilities' service territories. Relying solely on the small dataset to calculate these base credits may result in significantly over or under estimated values because the metered data is not a representative sample of the number of residential EVs.

The Proposed Amendments also state that, "The Executive Officer will use the following method to calculate the quantity of electricity used for non-metered residential charging: …*based upon the best data available* to the Executive Officer, during the compliance period".[8] (Emphasis added.) CARB staff has in fact been calculating the quantity of electricity used for non-metered residential EV charging on behalf of APU. APU encourages the Board to clarify the language and continue to calculate non-metered residential EV charging on behalf of smaller utilities, based upon the best data available

[8] Proposed Amendments to the Low Carbon Fuel Standard Regulation (March 6, 2018), Subsection 95486.1 (c)(1)(A)1. Calculation of Credits for EV Charging Using Fuel Pathways – For Non-Metered Residential EV Charging.

(ARPU1_42-1)

> **Agency Response:** The base credits for non-metered residential EV charging are estimated and issued to the opt-in EDUs based on the best available data for average EV charging rate and the EV population. Staff assesses the EV population in based on the DMV and CVRP data, whereas, the average daily EV charging rates are provided by the EDU for the crediting period. If the utility specific average EV charging rate is not available, staff calculates and uses a statewide average EV charging rate based on utility specific average rates. Staff has proposed to issue the base credits for non-metered residential EV charging on a quarterly basis to synchronize it with the crediting cycle for all other fuel types. Quarterly generation of credits for non-metered residential EV charging, rather than annual, would allow credit generators to monetize credits sooner. Therefore, it is critical for calculations and issuance of base credits that EDUs continue to provide any available daily EV charging rate for each quarter.

D-6.14. ***Incremental Credits for Residential EV Charging***

D-6.14a. ***Proposed Incremental Credits for Residential EV Charging***

Comment: LADWP recommends that ARB require any business that generate LCFS credits through this classification, must obtain the express consent of the customer on how the metered data will be used, pursuant to California Civil Code Section 1798.98. (LADWP1_38-7)

> **Agency Response:** Staff believes the California Civil Code Section 1798.98 establishes the regulatory requirements pertaining to businesses sharing customer data with a third party and, therefore, the LCFS regulation need not include any duplicative requirements.

D-6.14b. Multiple Comments: ***Clarifications for Proposed Incremental Credits for Residential EV Charging***

Comment: LADWP … recommends that **any** entity that generates incremental credits must meet the requirements set forth in paragraph 2 through 5 in section 95491(d)(3)(A). (LADWP1_38-6)

Comment: We … encourage CARB to clarify and simplify the processes to generate credits from electricity used for residential and non-residential EV charging.

…

3. <u>Simplify processes to encourage increased electricity use</u>

We offer the following comments related to *§94583, Fuel Reporting Entities* to streamline the reporting of electricity use as a transportation fuel:

a) *§95483(c)(1), Fuel Reporting Entity For Electricity Used as a Transportation Fuel, Residential EV Charging* – PG&E supports the electrical distribution utility (EDU) as the credit generator for base credits from EV charging. An entity that chooses to claim incremental EV credits may propose a method to CARB and utilize that method to make a claim. Furthermore, we believe that any entity generating incremental residential credits should meet the requirements of section §95491(d)(3)(A)(2) – (5). (PGE1_120-6b)

   Agency Response: Staff appreciates the commenters' support for keeping Electric Distribution Utilities (EDU) as the credit generator for base credits for residential EV charging. For generating incremental credits, staff proposed the accounting and reporting requirements instead of letting the reporting entities propose a method. This results in standardized accounting and reporting of electricity for incremental credit generation reducing the administrative review required by staff while ensuring consistency and accuracy of the data reported in the program. Staff proposed that entity generating incremental credits must meet the requirements set forth in paragraphs 2. through 7. in section 95491(d)(3)(A), as applicable.

D-6.14c. Multiple Comments: *Proposed Reporting for Incremental Credits for Residential EV Charging*

Comment: *SMUD supports the new option in the Proposed Amendments of linking non-metered EV residential charging to EDU green tariff programs, but supports the comments of CalETC that staff should develop a simpler method for EDUs to generate credits on behalf of their ratepayers.* SMUD has been a leader in utility green pricing programs for many years with its Greenergy program. Greenergy allows customers to purchase up to 100% of their power needs as Green-e certified renewable energy through a flat monthly fee on their utility bill. Greenergy has grown substantially over the years because of its low cost and simplicity.

The Proposed Amendments create a relatively complicated system of requirements to ensure that Greenergy customers who purchase low-CI electricity are the same customers who are charging EVs at home or at a participating workplace. Instead, linking customers who own or lease an EV with green tariffs should be relatively simple. The customer just needs to register the EV with the EDU with a proof of registration within some period after purchase or lease. EDUs can encourage high rates of registration through means of incentives. SMUD already has high rates of registration

through our “Free fuel for two years” program. CARB can incentivize even higher rates of registration by returning low-CI credit value to EDUs so they can provide yet higher return of the value from green energy programs. In addition, EDUs now have available new means of analyzing customer data to verify that the EV remains with the green pricing customer and charging at the residence. And because customer usage is exactly the same for incremental credits as for base credits in green tariff programs, there is no need to meter the incremental credits a second time for customers on green tariff programs.

SMUD urges staff to accept accredited EDU green pricing programs such as Greenergy and devise a simpler method of ensuring that those residential green pricing program customers indeed have EVs and generate credits from zero carbon intensity (0g/MU). (SMUD1_85-9)

Comment: 8. CalETC supports, in concept, the draft regulation order’s proposal for EDUs and other load serving entities (e.g. community choice aggregators) to generate incremental credits from charging that is linked to green tariff electricity but believes the current proposal is unworkable for EDUs and needs amending.

…

8. CalETC supports, in concept, the draft regulation order’s proposal for EDUs and other load serving entities (e.g. community choice aggregators) to generate incremental credits from charging that is linked to green tariff electricity but believes the current proposal is unworkable for EDUs and needs to be amended.

The draft regulation order proposes providing three options to recognize a reduced carbon intensity for renewable power supplied to electric vehicle charging stations that exceeds the carbon intensity from grid electricity.[10] CalETC supports two of these options (on-site generation and indirect accounting), and believes the third option, linking to green tariff electricity for charging, if amended, could be workable. Green tariff electricity is available from most investor-owned utilities and many publicly-owned utilities and community choice aggregators and it results in zero-carbon intensity (0 g/MJ). In addition, green tariff electricity would capture renewable electricity for EVs (Low-CI electricity pathway) that would not otherwise be claimed by automakers and charging station network providers who also could be generating Low CI incremental LCFS credits in residences. For example, well over 50 percent of the home charging market uses either level one charging stations or non-networked level two charging stations who are not on separately-metered EV rates.[11] These are the perfect candidates to sign up for green tariff electricity and earn the proposed incremental LCFS credits.

[10] The draft regulation order proposes allowing renewable electricity to be eligible for an improved carbon intensity score if it either green tariff electricity, on-site generation or indirect accounting through defined use of valid renewable energy certificates (RECs).

[11] These residential customers are typically on either traditional utility rates or whole house Time-of-Use rates that are designed for EVs. The large California utilities are transitioning to default Time-of-Use rates for residential customers over the next few years.

Linking customers who own or lease EVs with green tariffs should be a relatively simple process for estimated residential charging, as compared to the other types of renewable electricity pathways in the draft regulation order, which require extensive verification and applications for special Low-CI pathways. For example, a customer who buys an EV could at time of purchase apply to the EDU with proof of registration, sign up for a green tariff without a separate meter for EVs, and not have to reapply to the EDU for three years.

The draft regulation order does not provide a simple solution for green tariff electricity at residences or at non-residences. Instead, the draft regulation order has a complex system for separately metered electricity. For estimated residential electricity linked to green tariffs, the draft regulation order does not provide much guidance, but appears to set up complicated system that is likely not worth the effort to EV drivers or utilities.[12]

[12] For example the benefit of an EV charging at home is about one metric ton per year for the incremental low-CI credit at 0 g/MJ or one LCFS credit per year, which may not be worth the hassle of an application especially if it must be done annually.

CalETC recommends that in the 15-day change period, staff develop a separate set of simple, workable rules for green tariff electricity – especially for estimated residential charging. Further, CalETC recommends different rules for green tariff electricity that is metered and estimated. Since green tariff electricity is already regulated by the CPUC and Governing Boards of municipal utilities, a very simple process for look-up table applications, validation or auditing should be established compared to other types of low-CI electricity in the draft regulation order. In addition, for estimated residential charging with green tariff electricity the reporting rules should be made clearer and simpler (e.g., no registration of the type and serial number of home charging stations, no GPS co-ordinates, no need for site-specific CI information, and no need for annual EV registration). CalETC looks forward to working on these details with staff in the 15-day change period to develop a system that encourages EDUs to prevent green tariff electricity credits for EV charging at home from going unclaimed in the LCFS. (CALETC1_96-11)

> **Agency Response:** Staff appreciates the commenters' support and suggestion for the proposed provisions for generating incremental credits for residential EV charging. As part of the 15-day changes, staff proposed the incremental credit generator for non-metered residential EV charging must be able to provide Vehicle Identification Number (VIN) for each EV claimed and evidence of EV vehicle registration and low-CI electricity supply at the same location (e.g., green tariff enrollment) upon request of the Executive Officer. The Executive Officer shall use the formula in section 95486.1(c)(1)(A) for calculating the quantity of electricity eligible to generate incremental credits associated with each EV VIN that is not separately metered and is shown to receive low-CI electricity, and is not claimed by another entity for generating incremental credits pursuant to section 95483(c)(1)(B). The proposed amendment would simplify reporting for non-metered residential EV charging while preventing duplicate claims for generating incremental credits. See Response O-6.3 in this chapter clarifying

that staff will audit these credit generators but does not consider third-party LCFS verification necessary for electricity during this rulemaking.

D-6.14d. Multiple Comments: ***Proposed Hierarchy for Incremental Credits for Residential EV Charging***

Comment: III. The ARB should establish a simple customer-choice based hierarchy for awarding incremental credits for Low-CI supplied electricity. Under this hierarchy proposal, the EDU would be eligible as the default incremental credit generator for residential EV charging load not claimed by any other party for a calendar quarter. We We recommend the ARB undertake a thoughtful examination of instituting a hierarchy, including consideration of the role load-serving entities and metered charging, relative to automobile telematics. Automobile telematics may contribute to EV adoption, but will likely have less effect on procurement of low CI fuel. ARB must ensure orderly administration and operation of the LCFS market as it initiates incremental credits.

…

III. The regulations need to establish a customer choice-based hierarchy for claiming incremental credits in order to provide clarity and order in the incremental credit evaluations.

The ARB should enable non-EDUs ability to generate LCFS "incremental credits" from EV charging and create a hierarchy for generation of such credits.. The 45-day Proposed Amendments do not establish any priority or hierarchy for entities seeking to generate incremental credits associated with metered or unmetered residential EV charging. Instead, the Proposed Amendments simply say that "any entity, including any EDU" may generate incremental credits by registering the fuel supply equipment (FSE) and identifying an existing or new fuel reporting pathway. The Proposed Amendments further provide that <u>no</u> incremental credits will be issued in the event that two or more entities report for the same FSE.

This lack of hierarchy and recognition of customer choice, including changes over time, is problematic. It will lead to confusion and uncertainty where the customer may have a relationship with multiple entities eligible to generate LCFS credits. For example, a residential customer may be a customer of CCA, install an manufacturer's EVSE subsidized by an EDU or CCA program, to charge an electric vehicle, and utilize the services of an electric vehicle service provider ("EVSP). The existing protections (i.e., that double reporting of an FSE will nullify the credit) is not an effective solution here. The goal of the program is to optimize the generation of incremental LCFS credits and provide an incentive for the expanded use of clean energy for residential charging load.

Establishing a simple hierarchy based on customer service provider and customer choice makes sense. The Smart EV Charging Group specifically recommends that:

- EDUs should only be eligible to claim incremental credits for any calendar quarter based on the estimation methodology for incremental low CI service

provided to residential customers served by the EDU and whose FSE has not been registered by and reported by another Fuel Reporting Entity.

- Incremental credits may be claimed by non-EDU Fuel Reporting Entities for metered or unmetered residential EV charging through FSE registration authorized by the customer, or subsequent to original FSE registration as authorized by the customer.

This hierarchy will minimize the potential for unclaimed incremental credits by delineating between base and incremental credits for all residential EV charging volumes receiving incremental low-CI service. It will minimize conflicting reporting by non-EDU Fuel Reporting Entities by providing that the eligible reporting entity will be determined by evidence of explicit customer choice.

…

III. If the ARB does not change the EDUs' ability to generate base credits, then it should establish a simple customer-choice based hierarchy that retains the EDU as default credit generator for EV charging load not claimed by any other party by amending 95483(c)(1) as follows.

(c) *For Electricity Used as a Transportation Fuel.*

(1).*Residential EV Charging.* For on-road transportation fuel supplied for electric vehicle (EV) charging in a single- or multi-family residence, there are multiple possible credit generators:

(A).*Base Credits.* For residential EV charging, the EDU is the credit generator for base credits for EV charging in its service territory. The EDU must meet the requirements set forth in paragraphs 1. through 5. in section 95491(d)(3)(A).

(B).*Incremental Credits.* Any entity, including an EDU, is eligible to generate incremental credits (in addition to the base credits) for improvements in carbon intensity of electricity used for residential EV charging. An EDU that generates incremental credits must meet the requirements set forth in paragraphs 2. through 5. in section 95491(d)(3)(A). <u>The EDU can generate incremental credits for residential EV charging during a quarter only if not claimed by any other entity under this subparagraph B.</u>

In addition, the references to "fuel reporting entity" throughout should be clarified. For example, in Section 95483 – the "purpose of the section" is to identify the "first fuel reporting entities" and credit generators. But the subsection dealing with electricity doesn't mention fuel reporting entity for residential and non-residential charging, but then does in subsequent sections referring to guideway systems, forklifts, etc. Then, in Section 95483.1(a) the opt-in language seems to use the terms interchangeably – referring to "credit generator" in the first sentence, but "fuel reporting entity" in subsection (1)(A), which is the "opt in" section that would seem to apply to CCAs or EVSPs. Section 95482 refers to the entity "identified in section 95483" that is

“responsible” for reporting a transportation fuel. As noted, customer choice should dictate the Fuel Reported Entity, when applicable, such as for incremental credits from residential EV charging and non-residential EV charging, rather than “first” claim.

The ARB should also clarify the meaning of “an entity” in 95483(c)(2). The proposed language provides that “For electricity supplied for EV charging for on-road applications through non-residential charging equipment, an entity may generate credits…” as long as it meets program requirements and “no other entity is generating credits for the electricity dispensed through the same FSE. Simply saying “an entity” would allow anyone to claim credits for any non-residential charging (as long as they could access and register the FSE), rather the Smart EV Charging Group would recommend replacing “an entity” with “an entity that owns or operates the non-residential EV charging equipment, or its designee.”

Finally, the ARB should amend Sections 95483(c)(3), 95483(c)(4) and 95483(c)(5) to identify the LSE as the presumed back up credit generator for Fixed Guideway Systems in (c)(3), electric forklifts in (c)(4) and electric transportation refrigeration units in (c)(5). The ARB should replace the phrase “the EDU” with “the LSE supplying electricity to power the Fixed Guideway System”. (SEVCG1_116-5, SEVCG2_B10-5)

Comment: While ChargePoint commends the Air Resources Board for broadening opportunities within residential EV charging, we recommend establishing a hierarchy specifically for the incremental credits section. Prioritizing “EV Charging – Grid” over “EV Charging – Non-Grid” would best meet the primary goal of the Program, to focus on alternative fuels, by decreasing the carbon intensity of transportation fuels and providing more low-carbon and renewable alternatives. Allowing for telematics, while not explicitly referenced in the regulation, to be able to meter EV charging, helps incentivize electric vehicles, not necessarily the fuel that powers the vehicles. While incentives for electric vehicles are still critical at this stage of adoption, this is the one state program that focuses on alternative fuels, while there are other vehicle incentive programs, such as the Clean Vehicle Rebate Project (CVRP). Automakers have the ability to register vehicles at “point of sale” (or lease), while home chargers are typically purchased after the fact, and therefore would nearly default to being a vehicle program. Not to mention that verification and concerns of double-counting are much less of an issue through “EV Charging – Grid” versus geo-fencing which is more difficult to substantiate. (CHARGEPOINT1_122-2)

Comment: And lastly, we … recommend establishing a hierarchy for incremental credits. And in particular, we recommend prioritizing electric vehicle metered through the station versus metered through the vehicle itself. We think that without a hierarchy as such, it would disproportionately help incentivize vehicles, not fueling infrastructure; and given the executive order, which has the 2025 benchmark of infrastructure, 250,000 chargers in the ground by 2025, versus the 2030 farther-out goal of 5 million ZEVs on the road, we just think that getting that infrastructure to support the vehicles is critical.

We also think without the hierarchy there could potentially be a reduction in reliability and accuracy due to the difficulty to substantiate based on geofencing and other described methods in the proposed language. (CHARGEPOINT2_T8-5)

Comment: I did want to echo one point that ChargePoint made earlier. And it's really the need to consider some sort of hierarchy and how the Low Carbon Fuel Standard is implemented for this -- you know, these incremental credits. And because we don't know all of the different kinds of companies that are going to be out there, what kinds of technologies are going to be available, there really is a need I think to have some sort of order in the regulation for how the LCFS credits for the incremental credits would be granted to customers. And we think that, you know, basically doing that on a customer-choice-based model makes the most sense. (SCPA1_T28-3)

> **Agency Response:** Staff agrees with stakeholder comments that establishing a hierarchy for claiming incremental credits is necessary for simplifying reporting, preventing double counting, and providing incentive to the entities well-suited for providing low-CI electricity for EV charging. Therefore, as part of the 15-day changes, staff proposed a hierarchy for claiming incremental credits for metered residential EV charging. The LSE supplying the low-CI electricity has the first priority to claim credits as long as they can provide metered EV charging data for the purposes of credit generation. The manufacturer of the EV that can provide telematics data related to EV charging has the second priority; and any other entity that can provide metered data and demonstrate supply of low-CI electricity has the third priority. See Response O-6.3 in this chapter clarifying that staff will audit these credit generators but does not consider third-party LCFS verification necessary for electricity during this rulemaking.

D-6.15. *Credit Generator*

D-6.15a. Multiple Comments: *Proposed Credit Generator for Multi-Family Residential EV Charging*

Comment: Section 95483(c) describes who can qualify as a generator and Fuel Reporting Entity for electricity used as a transportation fuel. In 95483(c)(1) the regulation references that in both single- or multi-family residences the base credit generator is the EDU. SRECTrade would ask that CARB consider allowing the owner of the EV Charging Stations on site at a Multi-Family Property to opt-in, directly or through an agent, as the credit generator. We believe that the owner of the EV Charging Stations at a Multi-Family Property would be no different than the entity owning EV Charging Stations or FSE at a Non-Residential Property (i.e. a private workplace locations or commercial shopping centers). In many instances, the underlying owners of these properties responsible for initiating the investment in the FSE or EV Charging Stations could be the same entity. For example, many Real Estate Investment Trusts or other property owners maintain investments in both Multi-Family and Commercial or Industrial properties. It appears that allowing these property owners to be able to gain access to the same underlying incentive to make investments in EV Charging Stations and/or FSE should be available to them regardless of the type of property they own. (SREC1_111-2)

Comment: Additionally, while it makes sense from an equity standpoint to provide equal access to LCFS credits for both single-family homes and multi-family homes, multi-family charging can often be located in the "visitor" or "mixed-use" area of a multi-family residence, which is closer to "non-residential" in the usage. This could be an area of significant verification confusion if vehicles can register credits for chargers with multiple users, including non-residents. ChargePoint recommends removing multi-family from the residential section, or adding language that requires separating non-residential and residential (deeded/dedicated parking) EV charging at multi-family sites. (CHARGEPOINT1_122-6)

> **Agency Response:** Staff appreciates the commenters' insight and agrees that developing charging infrastructure at multi-family residence is critical for achieving states ZEV goals. Therefore, as part of the first 15-day changes, staff proposed the entity owning the Fueling Supply Equipment (FSE) in multi-family residences would be eligible to generate credits. However, stakeholder comments emphasized that EDUs are better suited to receive credits. As part of the second 15-day changes, staff proposed to keep EDUs as the credit generator for EV charging in multi-family residences as that would help support the statewide point of purchase rebate programs and other utility-specific programs promoting use of electricity as a low carbon transportation fuel, which could include infrastructure development in multi-family residences. Please see Response O-6.3 in this chapter clarifying that staff will audit these credit generators but does not consider third-party LCFS verification necessary for electricity during this rulemaking.

D-6.15b. Multiple Comments: ***Proposed Credit Generator for Non-Residential EV Charging***

Comment: There are two specific items that LCE and DE would like to include in upcoming amendments to the LCFS regulations, each relates to how CCAs can participate in the LCFS market. First, the ARB should clarify that CCAs are eligible entities that can register for non-residential EV LCFS credits through the proposed Section 95483.2(b)(8).

…

There are two specific items that LCE and DE would like to include in upcoming amendments to the LCFS regulations, each relates to how CCAs can participate in the LCFS market. First, the ARB should clarify that CCAs are eligible entities that can register for non-residential EV LCFS credits through the proposed Section 95483.2(b)(8).

…

Regarding non-residential EV charging, our interpretation of the eligible entities that can participate per the guidance in the proposed Section 95483(c)(2) appears to include CCAs if they meet the registration, reporting, record keeping, and auditing requirements

of that section. While CCAs may or may not own the Fueling Supply Equipment (FSE), they will identify the entity that they will be working with as per the requirements in the proposed Section 95483.2(b)(8)(B). We would like clarification that (1) CCAs are eligible to register as entity for non-residential EV charging and (2) any direction for how CCAs will be required to utilize revenue received from LCFS credits obtained from non-residential EV charging. (DELCE1_23-2)

Comment: Similar to our concerns about incremental credits for residential EV charging, the Joint POUs oppose allowing any entity to generate LCFS credits for electricity supplied for EV charging for on-road applications through non-residential charging equipment.[5] For non-residential EV charging—including but not limited to public access, workplace, fleet charging—site hosts, in addition to the EDU, may incur significant costs to install electric fuel supply equipment ("FSE"). The Joint POUs urge CARB to limit eligibility for non-residential EV credits to those entities bearing the costs to install, operate, and maintain the FSE, as well as grid infrastructure to deliver electricity to the FSE: site hosts and EDUs.

5 § 95843(c)(2)

If eligibility is limited to site owners and EDUs, then the Joint POUs support the provision in the proposed regulation order that non-residential EV credits will only be provided if no other entity is generating credits for the electricity dispensed through the same FSE. This will allow for constructive discussions between site hosts and EDUs regarding LCFS credit generation rights.

If eligibility is not limited to site owners and EDUs, then any entity generating LCFS credits for electricity supplied for EV charging for on-road applications through non-residential charging equipment should be required to reinvest revenue from sale of those credits into the EDU service territory in which the credits were generated to ensure that the customers incurring the costs to operate and maintain the grid infrastructure needed to deliver the electricity to the FSE also receive the benefits of the LCFS credits. (JPOUS1_59-4a)

Comment: 3. We recommend that ARB provide further clarification and a review of the proposed provisions around "non-residential EV charging" and "Time-of-Use" electricity pathways.

NRDC supports staff's efforts to increase the participation in the LCFS for non-residential EV charging by fleets or public/workplace charging. However, the provisions allow for any entity to claim credits that go unclaimed, without sufficient provisions to ensure that the workplaces, fleets, or public charging companies are notified of the value of the credits and the transfer of those property rights to the claiming entity. We recommend that the Board and staff work to ensure that the system is not abused by entities that may simply collect credits.

As an alternative, ARB could develop a methodology to estimate the amounts of electricity unclaimed and assign those credits to regulated utilities or charging providers, all of whom are required to provide the LCFS value back to the benefit of EV customers.

ARB could also allow entities who have existing rebate programs for charging infrastructure or electric vehicles to identify those unclaimed credits for purposes of those rebate programs. (NRDC1_81-8)

Comment: *SMUD is concerned that the proposed rule to allow any entity to generate credits from non-residential charging will confuse our customers and will not necessarily lead to greater capture of credit value in the long term.* The Proposed Amendments remove a provision that empowers property owners to be first in line to receive credit for transportation fuel supplied through non-residential EV charging. The rationale for the proposed removal is to enable the capture of more credits than are currently claimed by allowing any entity with fueling supply equipment (FSE) data access to claim the credits.

However, this rationale is mitigated to some extent because the price of credits is now over $100/credit and CARB predicts the price to remain above $100 through 2030. With a higher credit value, entities that are investing in EV charging, such as EDUs and EVSE owners, will be highly motivated to capture all the credits they can.

The proposed new structure sets the stage for a number of implementation problems. First, it is a recipe for conflict. The proposed rule grants the right to generate credits based solely on who registers the FSE first. While first-in-time rights in real estate or secured property have worked historically in other contexts, the law limits who may claim those rights to parties with an ownership interest in the property. Property law does this for the obvious reason that it would be fundamentally unfair for a third party to appropriate ownership of someone's property just because they manage to file a claim before someone else.

Second, a first-to-file rule could play into the hands of parties who might obtain consent from EVSE owners to claim the credits without fully informing them of the market value of the credit. This approaches fraudulent type behavior with little or no penalty to the party claiming the credits. Furthermore the process to re-register the FSE to the EVSE owner would cause a further loss of credits and would not be easy for normal property owners. SMUD has a strong interest in preventing fraud and providing clear notice to our customers of the potential value of LCFS credits.

Third, SMUD believes that it is inappropriate for entities who have not invested in creating the low carbon fuel, in building the charging station, or in providing another piece of the charging supply chain, to claim the credit value. EDUs also have the important obligation to use credit proceeds to benefit current and future EV customers. Opening up credit generation to entities without a vested interest in promoting the State's policies in reducing GHG emissions from transportation is not in accord with the basic goals of the Regulation.

Fourth, SMUD notes that the Proposed Amendments preserve current policy of preference and priority for mobile freight equipment such as forklifts, although SMUD does not completely endorse the new structure (which we will comment upon below). However, the point is that staff has seen the wisdom in maintaining a scheme that assigns authority to a specific party instead of allocating the right to generate credits to

whomever acts first. SMUD recommends that the Regulation should maintain as much consistency as possible across electrification applications, and an important consistency is a priority as to who can generate credits.

Lastly, the current structure essentially rewards data reporting over fuel delivery. Given that the Low Carbon Fuel Standard is a fuel regulation, prioritizing data reporting to claim the credits over the actual fuel production and delivery misplaces that value away from customers and EDU ratepayers who pay for delivery of low carbon electricity. Electricity customers and ratepayers have been the real enablers of transportation electrification by their support of grid development as funded through normal electricity bill payments. Without the past investment in grid development the ability to electrify transportation applications would be in question. Recent policy discussions around the LCFS have overlooked the benefits of that investment. The fact that EDU's are directed to support past and future customers in transportation electrification is the only vestige left of returning the LCFS back to the customers and ratepayers who have actually enabled this market to flourish. With regard to data reporting, the fact that much of the electricity being used for transportation electrification is not metered separately is a policy choice to keep the cost of electricity low to meet customer demands and also helps grow the market for EVs through lower electricity rates.

The better course is to keep a customer hierarchy, beginning with the EVSE owner. Arguably the EVSE owner deserves priority because that entity has invested in the fuel supply equipment and past and future improvements to the grid. If the EVSE owner has not taken advantage of its first-in-line priority within some period of time, then the EDU should be the next in line because the EDU has generated and delivered the low carbon electricity to the non-residential charging station and is obligated to return that value back to their customers. Following the EDU, other parties who contribute value to building out charging infrastructure should follow, such as data service providers. Whatever the priority, SMUD believes a hierarchy is necessary to avoid conflict and to promote further investment in badly needed charging infrastructure. (SMUD1_85-5)

Comment: 9. Due to concerns about potential fraud and poor customer experience, CalETC opposes the draft regulation order's proposal to allow "anyone" to generate LCFS credits for non-residential charging.

…

9. *Due to concerns about potential fraud and poor customer experience, CalETC opposes the draft regulation order's proposal to allow "anyone" to generate LCFS credits for non-residential charging.*

The draft regulation order proposes that any entity with metering capability be enabled to generate LCFS credits for electricity used in non-residential transportation electrification applications (specifically public-access charging and private-access charging such as fleet or workplace). In other words, there is no hierarchy of who gets the credits, as there is with other parts of the draft regulation order and for all other fuels.

CalETC supports the concept of allowing credit aggregators and others who market the LCFS to get the credits, but opposes the proposed regulation order unless amended with the following recommendations:

a. The electric vehicle supply equipment (EVSE) owner (charging station owner) should be the first-in-line credit generator. The charging station owner is a broad term that could be the tenant at the commercial property, the owner of the commercial property or the third-party owner operator of the charging station network. The EVSE owners (which in some cases is the EDU) make the investment in charging equipment. CalETC believes the best incentive for investment in infrastructure is to designate the EVSE owners to be the first fuel reporting entity, as described in the section for gaseous fuels,[13] or contractually allow another party to serve as the first fuel reporting entity. Similarly, this process is done for electric forklift fleets, the fleet operator[14] can contractually allow another party to take on the credit generating responsibilities.

[13] See draft regulation order at page 41. "Subsections (1)(A) through (1)(E) above notwithstanding, an entity may elect not to be the first fuel reporting entity for a given gaseous fuel, provided another entity has contractually agreed to be the first fuel reporting entity for the fuel on its behalf. In such cases, the two entities must agree by written contract that …….."

[14] See draft regulation order at page 42. "Subsection (A) above notwithstanding, the electric forklift fleet operator may elect not to be the credit generator and instead designate another entity to be the credit generator, if the two entities agree by written contract that…."

b. Requirements should be made the same for EDUs and other EVSE owners including using the value associated with the LCFS credits to support more transportation electrification.

c. If the EVSE owner is not the credit generator, and that responsibility has been assigned to another party, then additional requirements should be placed on that third-party credit generator that include the following:

    i. Be subject to the same requirements as EDUs and other EVSE owners

    ii. Obtain a written letter or contract, to allow the third party to generate the LCFS credits that includes a clear, high level explanation of the LCFS program, its value to the EVSE owner and why CARB has created the LCFS regulation.

This is especially important given that EDUs have begun programs to use the LCFS residential credit value to support transportation electrification. Some public utilities have already begun generating non-residential credits and investing LCFS credit value to support transportation electrification in the non-residential market segment (e.g., fleets, workplaces and multi-family installations). Investor-owned utilities have also begun implementing their programs for residential LCFS credits, which can be scaled to support non-residential transportation electrification. The CPUC has approved investor-owned utility programs for light duty EVs including non-residential charging programs and is poised to approve SB 350 utility programs, which will result in IOUs investing in non-residential charging. If other entities generate LCFS credits for non-residential applications, CalETC believes it is imperative that the value be used to support transportation electrification.

CalETC is concerned that allowing “anyone” to get the non-residential LCFS credits for EV charging will lead to a poor consumer experience (e.g. fleets, workplaces and retail) and potentially fraud concerns, not unlike what happened in the federal Renewable Fuels Standard. CalETC believes that it also is unnecessary. While it is true that in the past some parties were not generating these credits, this was primarily due to the few number of EVs and LCFS credit prices that were five or six times lower than today’s prices. CalETC believes that by making the charging station owner (EVSE owner) the first-in-line to generate these non-residential LCFS credits third parties will still be motivated to approach the EVSE owner for a contract because of today’s LCFS credit prices and increasing interest in EV adoption. (CALETC1_96-12)

Comment: b) *§95483(c)(2), Fuel Reporting Entity, For Electricity Used as a Transportation Fuel, Non-residential EV Charging* – We disagree with the proposal that any entity may generate credits. We are concerned that this provision could result in eligible LCFS credits not being generated by entities such as electric vehicle supply equipment (EVSE) owners. Instead we recommend that the EVSE owner is the first fuel reporting entity, as described in the section for gaseous fuels, or contractually allow another party to serve as the first fuel reporting entity. (PGE1_120-15)

Comment: IV. Non-Residential LCFS Credits should be granted based on customer choice of the FSE.

For the same reasons discussed above, the Smart EV Charging Group is opposed to the open-ended provision that “any entity” may generate credits for non-residential charging as long as it meets program requirements and “no other entity is generating credits for the electricity dispensed through the same FSE.” This is likely to create confusion and uncertainty among customers and program participants, and could result in credits being forfeited by multiple parties reporting the same load. The solution here is simple. Any entity should be allowed to claim credits for non-residential charging as long as the entity can establish that it has been selected by the owner of the FSE to do so. Evidence of customer choice should not be based solely on registration of the FSE, as multiple parties may have access to the FSE identifying information and/or the FSE may change hands over time. Evidence of customer choice should be a written authorization by the customer to the entity reporting the credits. (SEVCG1_116-6, SEVCG2_B10-6)

Comment: In order to ensure that all non-residential EV charging is accounted for, the regulations should authorize the LSE (EDU or CCA) providing generation service to generate credits for loads not registered and reported by the customer or its designee. (SEVCG1_116-6b, SEVCG2_B10-6b)

Comment: We do not support the staff's recommendation to allow non-residential credits for anyone. We have specific recommendations in our letter for how to treat those credits, but we would like them to go first to station owners, and then if aggregators want to step in and aggregate, we're fine with, but there needs to be some court of contractual agreement. (UTILITIES1_T47-4)

Agency Response: Staff agrees with the commenters that not establishing a credit generator for non-residential EV charging could result in confusion over reporting and could result in stranded credits. Therefore, as part of the 15-day changes, staff proposed that the owner of the Fueling Supply Equipment (FSE) supplying electricity for non-residential EV charging is eligible to generate credits. Although, if the owner of the FSE is not able to participate directly in the program it would have the flexibility to contractually designate another entity on its behalf to be the credit generator pursuant to section 95483(c)(2)(B).

In response to comment DELCE1_23-2, a CCA is eligible to opt-in as a credit generator for non-residential EV charging as long as it meets the FSE registration requirements and the reporting requirements for non-residential EV charging.

D-6.16. ***Proposed Reporting and Credit Calculation for EV Charging***

D-6.16a. Comment: To encourage greater installation of EV charging equipment, CARB should consider allowing non-metered/non-residential charging facilities to "opt in" as credit generating facilities. A non-metered/non-residential charging station contributes to lowering carbon emissions associated with transportation fuels in the State of California and therefore should be allowed to participate in the program.

Furthermore, in some situations, non-metered charging facilities may be the only affordable option, even for certain non-residential locations. As a matter of policy, CARB should take into consideration the disincentivizing effect of not allowing these locations to take advantage of LCFS credits. Although the calculation of charger consumption in these cases may be less precise than their metered counterparts, the marketplace has existed long enough to make reasonable estimates upon which reporting may be based.

For reporting purposes, non-metered, non-residential charging consumption can be calculated using registered, metered, non-residential data from the previous year to establish a baseline and an "unmetered" discount factor may be applied. See the equation below for more details:

$$QC_{NM} = UDF * QC_M$$

$QC_{NM} = Nonmetered\ Charging$ (MWh/charging port)
$UDF = Unmetered\ Discount\ Factor$ (%)
$QC_M = Metered\ Charging\ Baseline$ (MWh/charging port)

(3PR1_31-1)

Agency Response: Staff relies on separately metered data provided by utilities and estimated EV population based on DMV and CVRP data to calculate the base credits. Staff developed a methodology to calculate base credits for non-metered residential EV charging as most of the residential EV charging is currently not metered. However, most of the non-residential EV charging is

generally metered separately often using revenue grade meters for billing purposes leaving a very small number of non-metered non-residential EV charging. Staff does not believe a separate methodology is necessary for non-metered non-residential EV charging as it would add administrative complexity for reporting and crediting of EV charging.

D-6.16b. Comment: As part of this update, CARB must clarify that vehicle telematics is an acceptable data source for LCFS credit generation. We propose the following modifications to the regulatory text:

1. Change "metered charging data" references to "*measured* charging data" throughout the regulation;

2. Add a definition for "measured charging data" that includes utility-metered data, Electric Vehicle Supply Equipment (EVSE) data and vehicle telematics data provided by automotive manufacturers;

3. Update reporting requirements for measured residential EV charging in Section 95491(d)(3)(B) of the regulation to include Vehicle Manufacturers; and

4. Add new language to confirm that automakers can generate additional residential EV charging credits if fleet-wide, aggregated charging data from telematics exceeds CARB's charging estimates.

As a part of these updates, Tesla encourages CARB to establish reporting requirements that are easy to administer for EV manufacturers and that ensure the data is sufficiently aggregated to protect consumer privacy.

In summary, vehicle telematics data is the most comprehensive and accurate charging data available for the statewide fleet of EV charging today, and the use of this data will increase credit generation and improve the overall data integrity of the LCFS program. CARB should clearly define the role of vehicle telematics data for credit generation by modifying the definition of "metered charging data" to include this form of charging measurement and allow this data to be used to generate residential credits that are not currently captured through the estimation methodology. (TESLA1_79-2a)

Agency Response: As part of the 15-day changes, staff proposed further amendments to Fueling Supply Equipment (FSE) registration requirements for residential metered EV charging. Section 95483.2(b)(8)4. of the proposed regulation clarifies that on-vehicle telematics capable of measuring the electricity dispensed for EV charging can be registered as FSE with the Vehicle Identification Number (VIN). Staff proposed the electricity used for EV charging must be reported per FSE to generate credits. Thus, on-vehicle telematics can be used for reporting and generating credits as long as the VIN is used for the FSE registration. This change would allow data collected using telematics to be reported for generating incremental credits for residential EV charging when separate meters are not available to measure dispensed electricity. This would

also prevent any double counting of electricity for credit generation given only one entity would be able to report per VIN.

D-6.17. Multiple Comments: *Proposed Changes to Electric Forklifts Provisions*

Comment: *SMUD recommends that the Proposed Amendments maintain the current regulatory scheme whereby the EDU is the default credit generator unless the forklift fleet operator opts in.* The Proposed Amendments would make several changes to the current Regulation for electric forklifts, in addition to expanding the provision to other freight and goods movement equipment. SMUD believes that the current scheme would capture more credits and grant the right to generate credits to the entities that are most needed to invest in electrification of goods movement systems.

The existing rule has the advantage of designating a default party for generating credits, and given CARB's current process for calculating and awarding forklift credits to EDUs, those credits are sure to be created and monetized for future charging infrastructure. The current rule removes the uncertainty introduced by the Proposed Amendments, which requires the fleet owners to take affirmative steps to opt in to become credit generators. Because the credit value from one operation may not be great, small businesses may not spend the time and money to opt in (whereas the EDU can consolidate fleet electrification across its service territory).

In addition, SMUD created an incentive program in 2017 to support the electrification of goods movement systems. SMUD's Electric Forklift Incentive Program grants $1,000 to the forklift distributor and $2,000 to the fleet owner, because both parties must cooperate to electrify fleets. The change in the Proposed Amendments overlooks this supply chain. SMUD has plans to use the credits and data obtained in return for these incentives to propagate additional electrification, just as intended by the Regulation. However, the Proposed Amendments will bring into question SMUD's program just as it is beginning to take root. While SMUD supports needed changes to the Regulation, staff should not change the rules before EDUs are given time for their new electrification programs to work. (SMUD1_85-6)

Comment: For consistency, the Smart EV Charging Group would support a similar approach for Electric Forklifts and Other Mobile Freight Equipment and Electric Transport Refrigeration Units. (SEVCG1_116-6a, SEVCG2_B10-6a)

> **Agency Response:** As part of the 15-day changes, staff's proposal clarified that the forklift fleet owner would be the fuel reporting entity and the credit generator for electricity supplied to a specified fleet. To ensure more forklift fleets can opt in and participate in the LCFS, staff proposed that the forklift fleet owner may designate another entity to be the credit generator on its behalf. An EDU would remain eligible to generate credits for electric forklifts for which the fleet owner or its designee are not generating credits in the program.
>
> Staff proposed to include other mobile freight equipment in the LCFS including Electric Transport Refrigeration Unit (eTRU), Electric Cargo Handling Equipment

(eCHE), and Electric power for Ocean-going Vessel at-berth (eOGV). Staff proposed the owner of the Fueling Supply Equipment (FSE) that registers the FSE pursuant to section 95483.2(b)(8), to be the entity eligible for generating credits for supplying electricity for eTRU, eCHE, and eOGV. The FSE owner has an option to designate any other entity to be the credit generator on its behalf. This is consistent with other electricity categories where the first fuel reporting entity and credit generator is the FSE owner. Staff believes this would allow entities who are well suited to promote the use the electricity in mobile freight application to be able to report the use of electricity in the program and generate credits for incentivizing the use of electricity as a low carbon transportation fuel.

D-6.18. ***Requirements for Entities Generating Credits for Supplying Electricity as a Transportation Fuel***

Comment: With regards to the requirement for non-metered residential EV charging that an EDU must provide rate options that encourage off-peak charging and minimize adverse impacts to the electrical grid,[3] the Joint POUs recommend amending this provision to include "to the extent permissible by Article XIII C of the California Constitution." Proposition 26, approved by California voters in 2010, requires POUs, as local government entities, to charge rates for electric service that do not exceed the reasonable costs to the POU of providing the service.[4] While we believe that Prop 26 compliant rates can be designed that also provide the proposed encouragement for off-peak and adverse-impact minimizing, the requirement would be clearer if it recognized the existence of the Prop 26 provision in Article XIII C.

[3] § 95491(d)(3)(A)(4)

[4] Cal. Const., art. XIII C, § 1, subd. (e), par. (2).

(JPOUS1_59-2b)

Agency Response: Staff modified the proposed regulation section 95491(d)(3)(A)(4), as referenced by the commenter, to clarify only the Load-Serving Entities (LSE) generating credits for supplying electricity pursuant to section 95483(c) must provide rate options that encourage off-peak charging and minimize adverse impacts to the electrical grid. Different entities can play the role of LSE, including IOUs, POUs and CCAs, which are often governed by different rules and requirements for setting rate options. Therefore, staff proposed to keep the flexibility for the LSE to design and offer rate options as permitted by its local rules and governance without specifying any additional requirements.

D-6.19. ***Smart Charging Crediting***

D-6.19a. Comment: The addition of these pathways and the associated accountability underpin a number of significant problems with LCFS implementation:

1. These pathways are not subject to the same level of review, reporting or validation as Tier 1 or 2 fuel pathways. Proposed accounting mechanisms for certain proposed pathways appear onerous and difficult to verify when the EV charging occurred and the quantity of "fuel" dispensed during a discrete amount

of time, leaving regulated parties exposed to purchasing fraudulent credits. For instance, non-metered electric vehicle charging can produce incremental credits using a time-of-use pathway based on *estimated* electricity use of non-metered residential plug-in vehicles within a given EDU service area. Credit generators do not have to demonstrate that the charging occurred during a period when renewable energy would have been curtailed. The potential for fraud in this scenario is significant. (VALERO1_69b-4)

Agency Response: Staff disagrees with the commenter and would like to clarify that smart charging pathway, or as referred in the comment "time-of-use" pathway, can only be used with metered EV charging data. Staff proposed that to generate credits using smart charging pathway the reporting entity must provide the quantity of electricity used for EV charging for each hourly window per Fueling Supply Equipment (FSE). Further, upon request by the Executive Officer, the reporting entity must be able to provide documentation showing the further breakout of electricity used during a reporting period by hourly windows.

D-6.19b. Comment: On time-of-use charging, NRDC notes that there is significant research on the capability for utilities to integrate additional renewables through managed EV charging, including use of demand response. While there is a large potential, it is unclear how the additional for TOU charging would be additional if GTSRP programs that already credit for incremental electricity are fully utilized. We recommend that ARB make the TOU charging provisions a pilot program, pending a third-party reviewer analyzing the effectiveness of the provision based on the first two years of data, to ensure that the credits generated are truly enabling renewables that would have been curtailed otherwise. (NRDC1_81-10)

Agency Response: Staff acknowledges the commenter's concern about the potential double counting of GHG benefits through incremental credits as proposed in the staff's initial proposal posted on March 6, 2018. In that proposal, incremental credits could be generated using low-CI electricity and smart charging pathways for the same Fueling Supply Equipment (FSE). In response to this comment, staff modified the proposed regulation to require that incremental credits for residential electric vehicle (EV) charging per FSE may be generated for using low-CI electricity or for smart charging pathways but not both for the same FSE. Staff believes this change simplifies the reporting requirements and prevents double counting of GHG benefits.

D-6.20. Multiple Comments: ***Fuel Pathway Available For Reporting Electricity Used for Non-EV Charging Transportation Applications***

Comment: 2. Clarify that Lookup Table Fuel Pathways for electricity may be claimed by fixed guideway system operators;

…

2. CARB Should Clarify that Lookup Table Fuel Pathways for Electricity May be Claimed by Fixed Guideway System Operators That Meet Applicable Requirements

To avoid potential ambiguity, the draft LCFS Regulation should be modified to make clear that all lookup table pathways for electricity in draft Section 95488.5, Table 7-1 apply to the use of electricity as a transportation fuel for fixed guideway systems, in addition to electric vehicle charging. Currently, Table 7-1 of the draft LCFS Regulation identifies pathway ELCG (for grid average electricity), pathway ELCR (for 100 percent solar or wind-generated electricity), and ELCT (for electricity supplied under time-of-use provision), and each of these pathways specify that they may be used to report electricity supplied to electric vehicles. However, both the current LCFS Regulation and the draft revised LCFS Regulation define the term "electric vehicles" to include only "Battery Electric Vehicles (BEVs) and Plug-In Hybrid Electric Vehicles." Thus, as defined, the term "electric vehicle" does not include fixed guideway systems. Historically, however, the lookup table values for electricity have applied to the use of electricity as a transportation fuel for fixed guideway systems. In addition, BART understands, based on conversation with CARB staff, that staff intended the electricity fuel pathways in Table 7-1 to also be available to fuel reporting entities that are fixed guideway system operators, in addition to fuel reporting entities providing electric vehicle charging. CARB should clarify that this was its purpose by specifically referencing fixed guideway systems (as well as any other appropriate fuel reporting entities that use electricity as a transportation fuel) in the description of those pathways in draft Table 7-1.[2]

[2] Similarly, CARB should clarify that other provisions of the LCFS Regulations referencing the lookup table electricity fuel pathways available to electric vehicles are intended to apply to fixed guideway systems as well. Sections that should be clarified include proposed Section 95488.1(b)(2)(B) (reference to "Electricity associated with time-of-use pathways for EV charging and hydrogen production through electrolysis); proposed Section 95488.5(b)(1) ("The following information must be submitted with applications for the Lookup Table pathway for electricity generated from solar or wind supplied to EVs and time-of-use electricity supplied to EVs or hydrogen electrolyzers"); proposed Section 95488.5(d)(1) ("In order to reflect the rapidly evolving portfolio of electricity generating resources in California, the Executive Officer will update the "California Average Grid Electricity Supplied to Electric Vehicles" Lookup Table pathway CI value on an annual basis."); proposed Section 95488.5(f) ("The Executive Officer calculates a TOU carbon intensity Lookup Table each quarter for California grid electricity that may be used for reporting electric vehicle charging and hydrogen produced via electrolysis."), proposed Section 95488.8(i)(1)(A) ("Reporting entities may report electricity dispensed to electric vehicles or as an input to hydrogen production . . . .").

The requested clarification is also consistent with existing CARB policy. CARB has long intended that electricity-fueled fixed guideway public transportation systems be treated similarly to on-road electric vehicles under the LCFS Regulation. For example, in staff's Initial Statement of Reasons for Proposed Rulemaking – Proposed Re-Adoption of the Low Carbon Fuel Standard (December 2014) ("2015 ISOR"), staff noted that the Board directed staff in Resolutions 09-31 and 11-39 to evaluate the feasibility of issuing LCFS credits for non-road, electricity based transportation sources, including mass transit. 2015 ISOR at ES-14. In response to this Board request, staff identified fixed guideway transit systems and electric forklifts as categories of off-road electric transportation that use significant and quantifiable amounts of electricity for fuel. *Id*. BART believes that CARB remains fully committed to including fixed-guideway systems in the LCFS regime, and supports this policy approach. Accordingly, draft Section 95488.5, Table 7-1 should

be amended to clarify that the lookup table pathways for electricity used as a transportation fuel are available to fixed guideway system operators. (BART1_12-2)

Comment: San Francisco's primary concern is that electrified public transit that uses "fixed guideways" (such as Muni) is treated similarly to other transportation sources, such as electric and hydrogen-powered vehicles, for purposes of having their lower carbon intensity (CI) reflected in the LCFS calculations. As noted in our previous comments, the SFPUC provides 100% GHG-free electric energy to over 300 electric overhead-catenary (trolley) buses, 150-light rail vehicles (LRVs), and over 40 cable cars that are part of the Muni fleet, one of the largest electrified public transit fleets in the country. These zero-GHG vehicles operate on "fixed guideway systems," as defined in Section 95481(a)(35) of the LCFS regulations.

To ensure that the contribution of these vehicles is counted towards achieving the GHG reduction goals of the LCFS regulations, San Francisco proposes that the LCFS regulations be changed as follows:

1. Fixed Guideway Systems should be eligible to receive LCFS credits based on participation in a Green Tariff program

...

<u>Fixed Guideway Systems should be eligible to receive LCFS credits based on participation in a Green Tariff program</u>

Fixed guideway systems should be eligible to participate in a green tariff program in order to receive additional LCFS credits reflecting the lower carbon intensity associated with the electric energy provided to these systems.

While the regulations state their intent that this option be available to all "electricity supplied as a transportation fuel" (Section 95488.8(i)(1), p. 155), the regulatory language that follows refers only to "electric vehicles" or electricity used as an "input to hydrogen production" and does not include eligibility for fixed guideway systems. While the intent may have been that electric buses and LRVs on fixed guideway systems would fall into the "electric vehicle" category, this is not supported by the narrow definition of electric vehicle contained within the regulations.[1]

[1] Under Section 95841(a)(38), page 9 an "electric vehicle" is defined as; "Battery Electric Vehicles or Plug-in Hybrid Vehicles," which would exclude public transit electric vehicles using fixed guideway systems.

There is no reason to treat an electric bus operating on a street that is powered by electric batteries differently from an electric bus powered by overhead power lines. Both buses will access the same electric system with the same associated CI. Accordingly, the proposed regulations should be modified to include fixed guideway systems as eligible for green tariff programs. (CCSF1_87-1)

Comment: <u>Clarification of Eligibility of "Fixed Guideway Systems" for a Green Tariff program;</u> …

…

On-Road Electric Motorcycle	4.4	Electricity/Fixed Guideway, Trolley Bus, Cable Car, Street Car	3.1	

…

(B) Electricity associated with time-of-use pathways for EV charging fixed guideway systems and hydrogen production through electrolysis

…

ELCG	California average grid electricity supplied to electric vehicles and fixed guideway systems in California	93.42 (and subject to annual updates)

…

(A) Reporting entities may report electricity dispensed to electric vehicles and fixed guideway systems or as an input to hydrogen production… (CCSF2_90-1)

Comment: Finally, the Proposed Amendments creating a green tariff/low-CI approach are only available to electric vehicles and electricity used to generate hydrogen for vehicle usage. This excludes program eligibility to an entire class of vehicles, "fixed guideway systems" such as BART, San Francisco MUNI, and potentially the Sonoma and Marin counties' SMART rail service. The exclusion may also discourage EV charging in new EV program that public transit agencies may wish to deploy for buses. Eligibility should be extended to this class of transportation vehicles. (SEVCG1_116-6c, SEVCG2_B10-6c)

Agency Response: As part of the 15-day changes, staff proposed to modify the description of Lookup Table pathways in sections 95488.5(d), (e), and Table 7-1 to clarify that the electricity Lookup Table pathways could be used for reporting electricity used as a transportation fuel in all the non-EV charging applications listed in sections 95483(c)(4) through (7), including electric fixed guideway systems. This includes Lookup Table pathways that could be used for reporting low-CI and renewable electricity based on indirect book-and-claim accounting, including low-CI supplied through a green tariff program. Given other electric transportation applications does not allow the same level of flexibility to shift the use of electricity in time as EV charging and hydrogen production, staff proposed the smart charging and smart electrolysis pathways be available only for EV charging and hydrogen production through electrolysis, respectively. Allowing other applications to use smart charging or smart electrolysis pathways would require metered and hourly accounting and reporting of electricity which would

have created complexity. Staff would consider allowing smart charging pathways to other electric transportation applications in future if required level of accounting and reporting capabilities could be demonstrated.

D-6.21. *Fueling Supply Equipment (FSE) Registration for Electric Transportation Applications*

D-6.21a. *FSE Registration for Residential EV Charging*

Comment: LADWP understands the importance of preventing double counting and the value added from implementing the Fueling Supply Equipment (FSE) identification requirement. However, certain aspects of the requirement need to be clarified or amended.

FSE is not defined in the definition section 95481 of the regulation. With respect to electricity as a fuel, the term "equipment" can refer to the meter or the charger. The issue is that there could be multiple EV chargers connected to one meter. In this case, only the meter should be registered for a FSE ID as it is the measuring device providing the data needed for reporting purposes, and registration of the charger provides no added benefit. However, this setup may be insufficient for distinguishing time-of-use (TOU) data. LADWP recommends defining FSE in the definition section, and propose that the definition be "the equipment that provides the fuel throughput data for that specific location." (LADWP1_38-8a)

Agency Response: As part of the 15-day changes, staff proposed modifications to section 95483.2(b)(8) to clarify Fueling Supply Equipment (FSE) registration requirements for each transportation application type. These modifications provide clear instructions on what constitutes an FSE for each transportation application and what information is required to complete the FSE registration. Staff clarified that for non-residential EV charging, FSE refers to each piece of equipment capable of measuring the electricity dispensed for EV charging. For residential metered EV charging, FSE refers to a piece of equipment or on-vehicle telematics capable of measuring the electricity dispensed for EV charging. For electric forklifts, Electric Cargo Handling Equipment (eCHE), and Electric shore power supplied to Ocean-going Vessels at-berth (eOGV), FSE refers to the metering equipment at the facility or location where electricity is dispensed for fueling. For electric Transportation Refrigeration Unit (eTRU), FSE refers to each eTRU. For fixed guideway systems the LRT-CBTS will assign FSE IDs upon request based on the account registration information provided in the LRT-CBTS. For other electric transportation applications not covered in section 95483.2(b) 1. through 8., FSE refers to a fuel dispenser or a transportation equipment with the capability to measure the dispensed electricity in that equipment.

D-6.21b. Multiple Comments: ***Removal of FSE Registration Requirement***

Comment: In the current proposal, "fuel reporting entities for metered residential EV charging must provide the serial number assigned to the FSE by the OEM and the name of the OEM," as well as, "name and address of the entity that operates or owns the FSE, if different from the entity registering the FSE." This new language implies that every individual metered residential EV charger will need to be registered for its own FSE ID. The new requirement will allow CARB to identify the location and amount of EV charging for individual residential customers. While this data may be useful, it is not necessary to prevent double counting in most cases, and does not provide reduction in CI. It is not necessary because EDUs are the only entities that are able to claim metered residential EV charging credits within their service territory. However, it may be necessary to prevent double counting of incremental credits, where anyone can claim the credits. LADWP recommends the removal of this requirement for metered residential EV charging, with the exception for generation of incremental credits. (LADWP1_38-8b)

Comment: 11. CalETC does not support the CARB staff amendment to the regulation requiring every residence with a metered charger to be registered as "fuel supply equipment."

…

11. *CalETC does not support the CARB staff amendment to the regulation requiring every residence with a metered charger to be registered as "fuel supply equipment".*

CalETC believes the current system in LCFS for metered residential grid-electricity credits is appropriate and preferred, including the auditing provisions, and does not support staff's amendment to the system. The draft regulation order requires an unworkable system for the EV driver, as each house, apartment or condominium would need to be registered as "fuel supply equipment" (with charging station type and serial number) and provide proof that they have an EV annually. This makes LCFS an annual chore for EV drivers and for EDUs when there is desire by most to have utilities shift their programs to up-front rebates as close as possible to the point-of-sale. While EDUs do not have large numbers of EV drivers with metered electricity, these LCFS credits should not go unclaimed due to a new onerous system for EV drivers.

CalETC believes the draft regulation order on this topic creates a disincentive where fewer EDUs and fewer EV drivers will want to report this data because of the negative customer experience and onerous reporting. CalETC requests that staff be directed in the 15-day change process to return to the current, simple LCFS system for metered electricity credits by EDUs for residential charging (grid-electricity).

If CARB is seeking better data, CalETC suggests the following options: (1) use the auditing provisions in the current LCFS to provide data requests to the EDUs, (2) provide a simple template for EDUs to report on-line that does not request customer specific data or otherwise violate privacy laws, or (3) use other sources of data available

to CARB today.[15] CalETC has long advocated for CARB to use the best available data sources in order to estimate the residential credits provided to EDUs by CARB.

[15] CARB already has extensive data on kWh by make and model of EV which was cited in the ZEV mid-term review, or could use data on vehicle mileage and USEPA car label data on electric miles and electricity use per mile to calculate.

(CALETC1_96-14)

Comment: *§95483.2(a)(8)(F), Registration of Fueling Supply Equipment (FSE), metered residential EV charging* - We disagree with the requirement to provide the serial number assigned to the FSE by the original equipment manufacturer (OEM) for metered residential EV chargers. PG&E has fewer than 350 customers (<1%) who have separately metered residential EV chargers. Although we do have access to their meter details, we do not have access to the FSE information, which is owned by the resident. We believe that collecting and separately reporting this customer-specific data will add an administrative burden and not increase the number of credits that will be generated.

In addition, we recommend that the regulation not require the EDUs to provide specific customer information for separately metered residential EV charging, in order to reduce administrative burden and protect customer privacy. (PGE1_120-18)

> **Agency Response:** As part of the 15-day changes, staff proposed modifications to section 95483.2(b)(8)(B)4. to clarify that Fueling Supply Equipment (FSE) registration for residential EV charging is optional when reporting metered electricity to generate base credits. However, staff believes the FSE registration is necessary for reporting metered electricity to generate incremental credits to avoid any double counting of incremental credit for which multiple entities could be eligible as a credit generator. Opt-in entities reporting metered electricity for generating incremental credits must register an FSE by providing the Vehicle Identification Number (VIN) of the vehicle expected to be charged and if an off-vehicle equipment is used for measuring electricity then the unique serial number assigned by the Original Equipment Manufacturer (OEM) and the name of the OEM. Staff clarified that location information and address is not required to register FSE for reporting residential EV charging to ensure customer privacy.

D-6.22. Multiple Comments: *Opposition to Proposed Amendments and Proposals by Automakers that they be Eligible to Generate Credits for EV Charging*

Comment: However, the Joint POUs oppose proposals that would allow automakers to generate either incremental residential credits or non-residential credits.

…

The Joint POUs oppose the proposed regulation order provision that any entity is eligible to generate incremental credits for residential EV charging.[2] As an alternative, the Joint POUs urge CARB to limit eligibility to load serving entities.

[2] § 95843(c)(1)(B)

…

For either residential or non-residential EV charging, the Joint POUs oppose proposals that would allow automakers to generate LCFS credits from EV charging. EDUs are required to "use all credit proceeds to benefit current or future EV customers." With automakers there is no such guarantee that LCFS credit revenue would be reinvested to the benefit of the local communities in which the credits were generated and this revenue may in fact leave the state entirely. Investments in grid infrastructure—including upgrades to support EV charging—is particularly critical to ensuring the continued growth of EV adoption. Unlike an automaker, which targets specific customer segments likely to purchase their particular vehicles, POUs focus on brand-neutral investments that benefit the full range of EV customers, including traditionally underserved markets, such as low-income households, multifamily dwelling residents, and small business owners. (JPOUS1_59-4)

Comment: *SMUD opposes proposals to have automakers earn residential base credits.* (SMUD1_85-3)

Comment: 2. CalETC opposes 15-day change proposals by other, non-CARB, entities allocating base residential charging LCFS credits to automakers. Per #1 above, we support the residential credits being allocated to utilities. CalETC supports a CARB-led process working with utilities, auto makers and other stakeholders to expeditiously design LCFS-funded utility programs that best accelerate the electric vehicle market.

…

2. *CalETC opposes 15-day change proposals by other, non-CARB, entities allocating base residential charging LCFS credits to automakers. Per #1 above, we support the residential credits being allocated to utilities. CalETC supports a CARB-led process working with utilities, auto makers and other stakeholders to expeditiously design LCFS-funded utility programs that best accelerate the electric vehicle market.*

While CalETC is open to changes in how the utilities' LCFS credit proceeds from residential charging are distributed, this topic is very complex and deserves a thoughtful stakeholder process. It would not be appropriate for this substantial modification to the LCFS regulation to be made as a 15-day change. CalETC recommends that CARB staff, utilities, auto makers and other stakeholders work together to expeditiously determine the best utilization of the utilities' LCFS credit value. Point-of-sale rebates, as suggested by some auto makers, are an appealing option and could be funded with the utilities' LCFS credit value. It is also important for the utility programs to benefit communities most impacted by pollution and poverty, help ensure adequate fueling infrastructure is available to all, and reduce electricity fuel prices.

CalETC has already begun discussions with auto makers, CARB and other stakeholders to explore options to improve utility investment of LCFS credit value. These discussions have not yet resulted in consensus on how best to invest the LCFS

credit revenue but with CARB's participation, CalETC believes we can move expeditiously to improve the utility programs. (CALETC1_96-4)

Comment: Tesla and Ford have advocated for residential LCFS credit value allocated to auto makers. Although CalETC would like to consider how better to ensure the credit value best accelerates the ZEV market and benefits ZEV purchasers, CalETC is not supportive of shifting LCFS credit value to auto makers. (CALETC2_130-6)

> **Agency Response:** Staff acknowledges commenters' opposition to assigning base credits for residential EV charging to automakers and notes that utilities remain the sole credit generator for residential base credits in the staff's proposal. Staff believes EDUs are best suited to be the base credit generator as they are the primary fuel provider for residential EV charging given their role in developing low-CI electricity generation resources and maintaining transmission and distribution networks essential for delivering fuel for EV charging.
>
> In further response to the commenter's suggestion related to the eligibility for generating incremental credits in JPOUS1_59-4, staff would like to note that it was proposed to allow automakers as one of the eligible entities to generate incremental credits. Please see Response D-6.24a in this chapter.

D-6.23. Multiple Comments: Recommending that the LSE be the Base Credit Generator for Residential EV Charging instead of the EDU

Comment: In particular, the after the fact rebates provided by the IOUs through their LCFS revenue do little to spur new EV deployment when compared to programs like Sonoma Clean Power's Drive Evergreen program. It is timely and appropriate to amend the LCFS regulations to recognize the emergence of non-EDU load serving entities (LSEs). (SEVCG1_116-3a, SEVCG2_B10-3a)

Comment: II. Revise the Base Credits provision to identify the LSE serving generation to residential load (which may be an EDU or a CCA), rather than solely the EDU, as the base credit generator.

…

II. The LCFS regulations should reflect the fact that EDUs are no longer the sole driver of additional EV adoption and transportation electrification.

While the Proposed Amendment language enabling other entities to generate incremental residential credits mark an improvement to the LCFS regulations, the Proposed Amendments continue to identify the EDU as the exclusive credit generator of base credits for residential metered and non-metered loads. This approach reflects anachronistic assumptions and should be reexamined.

As the LCFS is intended to lower the GHG intensity of transportation fuels, it is reasonable that the "fuel" provider – in this case, the electricity provider – should garner the base credit for displacing diesel and gasoline. According to a recent CPUC white

paper, some estimate that up to 85 percent of retail load historically served by IOUs will be served by CCAs (or other non-IOU sources) by the mid-2020s.[2] In light of this trend, it is inequitable and inaccurate to continue to assume that the EDUs will be the de facto providers of generation service to residential load, and the de facto administrators of programs aimed at expanding EV adoption. Instead, residential base credits should be allocated to the entity serving the load.

[2] CPUC Staff White Paper, "Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework". Issued May, 2017. Available online at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/Retail%20Choice%20White%20Paper%205%208%2017.pdf

The shift to CCAs is a positive development for the complementary goals of increased EV adoption and charging from the cleanest sources possible. CCA LSEs are taking increasingly active roles in stimulating first-time EV purchases. As not-for-profit institutions with focused territories and leadership elected by the communities they serve, CCAs have a uniquely strong understanding of and communication with their customers. Moreover, many CCAs were established with the specific charter of reducing community-wide GHG emissions, not just by reducing emissions intensity in the electricity supplied, but also by encouraging fuel switching from fossil fuels to clean electricity on a broad scale. Given the connection to local government, many transit agencies are prepared to work with CCAs in furthering large-scale electrification networks (e.g. EV buses).

CCAs are best suited to administer the funds generated from the LCFS in furtherance of EV charging in the local communities. As non-profit agencies, CCAs have both tools and motivation to tailor EV-related programs to the specific needs and barriers to adoption that occur in their communities. The current EV rebates provided through the CPUC's program are relatively small, and not well-publicized. Additionally, as Board Member Sperling pointed out in his April 19, 2018 interview on Capitol Public Radio with Beth Ruyack, the large IOUs provide EV rebates after the point of purchase, which has little effect on the customer's decision to switch from a gasoline vehicle to an EV. The parties to these comments do not believe the current rebate system meaningfully facilitates EV growth. Better programs can and should be designed to facilitate new EV growth and transportation electrification.

For example, Sonoma Clean Power (SCP) was a pioneer in demonstrating how CCAs can support and encourage transportation electrification. SCP established its EV program, which was funded solely by SCP customers (i.e., no state contribution), in the Summer of 2016. The program has already exceeded its original objectives for expanding EV adoption and smart EV charging. For example, 773 additional EVs were sold in 2016 and 2017, putting SCP well ahead of its goal of 1,000 EVs by 2020. Particiapnts received an average discount of over $11,000 (before State and Federal tax incentives) and learned of the program through direct mailers from SCP, word of mouth, and newspaper advertisements.[3] In addition, over 1,700 charging stations have been installed on customer sites through a complementary program. In Southern California, the Antelope Valley Transit Authority (AVTA) set a goal of becoming the nation's first fully electric fleet by the end of 2018, and plans to convert all of the agency's aging diesel buses to a 100% battery electric bus fleet with up to 85 new

all-electric buses.On September 1st, 2017, AVTA made history by becoming the world's first transit agency to operate a 60' all-electric articulated bus in revenue service Charging infrastructure is another component of the project, which will use high-power wireless inductive chargers to help power the new zero-emission buses. These chargers will allow the electric buses to charge wirelessly simply by driving the vehicles over charging pads embedded into the ground. Several other CCAs and transit agencies are developing similar programs, and their collective influence on EV adoption will only increase as communities across the state continue to bring new CCAs online. Enabling CCAs to access LCFS credits associated with their residential customers' full load (i.e., the base credit in addition to incremental low-CI credits) will enhance the CCAs' ability to develop, market, and support EVs, EV charging programs, and EV public transit programs in their respective territories.

[3] Orose, Jamie; Pallonetti, Nicholas; and Jones, Michelle (2018), "Drive EverGreen 2.0 Incentive Program: Final Evaluation Report," Center for Sustainable Energy, San Diego CA, April 2018. Available online at: https://sonomacleanpower.org/wpcontent/uploads/2016/03/DEG2.0_EvalReport_FINAL.pdf

The Smart EV Charging Group recommends providing the entire residential base credit to CCAs. The existing process wherein EDU applications and EV VIN numbers are used to verify and grant residential LCFS credits can be adapted to allocate residential base credits between CCAs and EDUs. CCAs serve the vast majority (typically over 90%) of residential customers in their service territory, so a reasonably simple approach would be to assume every EV registered in that city or county takes residential generation service from the CCA. Alternatively, a very similar framework to what is used today could be used to verify which provider a specific customer takes service from. Today, EDUs regularly submit a spreadsheet (called a "4013") to CCAs and their billing departments. This spreadsheet lists every customer in the service territory by name and address, with an indication of whether they take generation service from the EDU or CCA. This snapshot could be coupled with CARB's existing database showing addresses of EV owners to verify which entity provides generation service to a specific residential customer. This, in turn, would determine which entity (the EDU or CCA) earns and administers the corresponding credit for that residential EV charging load.

…

II. Revise the Base Credits provision to identify the LSE serving residential load (which may be an EDU or a CCA), rather than the EDU, as the base credit generator, by amending Section 95483(c)(1) as follows:

(c) For Electricity Used as a Transportation Fuel.

(1) Residential EV Charging. For on-road transportation fuel supplied for electric vehicle (EV) charging in a single-or multi-family residence, there are multiple possible credit generators:

(A) Base Credits. For residential EV charging, the EDU is the credit generator for base credits for EV charging in its service territory <u>unless a Community Choice Aggregator has opted into the program and hence will become the base credit</u>

generator. The EDU or CCA as applicable, must meet the requirements set forth in paragraphs 1. through 5. in section 95491(d)(3)(A).

(B) Incremental Credits. Any entity, including an EDU, is eligible to generate incremental credits (in addition to the base credits) for improvements in carbon intensity of electricity used for residential EV charging. An EDU that generates incremental credits must meet the requirements set forth in paragraphs 2. Through 5. in section 95491(d)(3)(A). (SEVCG1_116-4, SEVCG2_B10-4)

Comment: Second, the ARB should reconsider the allocation of Residential EV Charging credits to not just electric distribution utilities (EDUs), but also to CCAs. This change will allow the growing CCA customer base access to LCFS revenues to support EV incentive programs.

…

Second, the ARB should reconsider the allocation of Residential EV Charging credits to not just electric distribution utilities (EDUs), but also to CCAs. This change will allow the growing CCA customer base access to LCFS revenues to support EV incentive programs.

…

For residential EV charging, we recommend that the ARB strongly reconsider its allocation of all credits to the EDUs. As ARB staff is aware, the CCAs are taking over a substantial portion of the load in California, comprising roughly 15 percent of the CPUC regulated load in 2018, 20 percent in 2019[1], with projections as high as 85 percent over the next decade. Without at least a portion of the residential EV charging credits allocated to the CCAs, a very large portion of California customers will miss out on a source of credits that their utility could use to provide incentives for greater electric vehicle adoption. These credits will allow CCAs to further innovate and provide the programs that their communities desire. One of the primary drivers for CCA formation was to help communities develop programs to meet their local goals. For those CCAs focused on greenhouse gas (GHG) reduction efforts, allocation of residential EV charging LCFS credits would provide a great benefit. These sentiments have been expressed in past filings by CCAs to the ARB on the LCFS program, such as those from Sonoma Clean Power (November 2016) and Pioneer Community Energy (November 2017).

[1] https:/ / www.publicpower.org/periodical/article/california-puc-approves-requirements-ccas

There are many different options that the ARB should explore when considering how to allocate LCFS credits between the EDUs and the CCAs. Options include providing all future credits to the default utility in a particular location, allocating credits proportionally to the level of program engagement or investment that is not stimulated by LCFS credits, or using the CCA formation date as the cutoff for when EVs registered in a CCA service territory receive LCFS credits allocated to a CCA. In regulations developed by the CPUC for Electric Service Providers (ESPs) and CCAs there is precedence that should help to shape this structure. For example, in CPUC Decision 16-01-032, ESPs

are credited with half the energy storage capacity for any Self Generation Incentive Program (SGIP) funded projects installed by their customers. While the SGIP program is administered by the Investor Owned Utilities (IOUs), all customers pay public service charges and thus the benefits should be shared. Similarly, the benefits that are gained through the allocation of LCFS credits should not be limited to just a shrinking pool of IOU customers, but rather should be shared across the entire customer base. (DELCE1_23-3)

Comment: In addition, we recommend that the residential base credits be allocated to the entity serving that customer's load. (CHARGEPOINT1_122-7b)

> **Agency Response:** Staff appreciates the commenters' suggestions to make the Load Serving Entities (LSE), including Community Choice Aggregators (CCA), to be eligible for claiming base credits for residential EV charging. Staff believes the LSE plays a critical role in supporting electrification of transportation but EDUs are the primary fuel provider for residential EV charging given their role in developing low-CI electricity generation resources and maintaining transmission and distribution networks essential for delivering fuel for EV charging. The base credits for non-metered residential EV charging are estimated and issued to the opt-in EDUs based on the best available data about average EV charging rate and the EV population in each EDU service territories. Assigning base credits to LSE would require data specific to LSE's service area requiring careful data collection and separation of data for CCA's service area which are often carved within EDU's service territories. This would add complexity and could potentially risk double counting or underestimation of residential base credits.
>
> Since the first Board hearing in April, utilities and automakers have been engaged in ongoing discussions to determine the best utilization of LCFS credit value for residential EV charging, including the development of a statewide point-of-purchase rebate program for EVs. To facilitate a statewide rebate program, staff proposed a few minor modifications to the proposed amendments. One modification would require EDUs to contribute a portion of the base credits or the base credit proceeds to the statewide rebate program should one be established. Allowing CCAs to claim base credits could reduce the number of credits available for the proposed statewide rebate program (or increase the complexity of pooling credits for such a program). Therefore, staff proposed to keep EDUs as the sole credit generator for base credits for residential EV charging.
>
> In further response to DELCE1_23-3, if a statewide rebate is established it would be available to all the EV buyers across California and will not be limited only to the customers in the service territories of opt-in utilities.

D-6.24. ***Automakers as the Base Credit Generator for Residential EV Charging***

D-6.24a. Multiple Comments: ***Recommending that the Automakers be the Base Credit Generator for Residential EV Charging instead of the EDU***

Comment: However, the current LCFS legislation and staff's proposed amendments,

- Introduce unnecessary reporting complexity and, in practice, limit EV manufacturers' participation to the incremental EV charging pathways,
- Undermine the State's own ZEV goals by further compartmentalising CARB policies, fragmenting and limiting opportunities

Jaguar Land Rover invites the Air Resources Board to develop the LCFS EV charging reporting requirement and market participations on the realization that **the common denominator across all EV charging events is the electric car.**

We, therefore, request that the California Air Resources Board:

- Clearly and very specifically allow EV manufacturers to claim Non-Residential EV charging credits and base reporting based on actual vehicle charging records.
- Allows EV manufacturers to opt-in to the metered Residential EV charging pathway. (JLRNA1_44-2)

Comment: 1. Data-Backed Credit Generation: permit EV manufacturers to utilize fleet-wide, aggregated charging data from vehicle telematics to earn additional residential LCFS credits if real-world charging exceeds CARB's estimated charging for the manufacturer's fleet.

…

I. Permit EV manufacturers to utilize fleet-wide, aggregated charging data recorded by vehicle telematics to earn additional residential LCFS credits if real-world charging exceeds CARB's estimated charging for the manufacturer's fleet.

Traditional sources of measured charging data, such as smart chargers or separate household utility meters, capture a very small percentage of total charging sessions. As a result, CARB is relying on high-level estimates to calculate residential charging credit generation. In 2017, only 1% of the credits that utilities received was generated from data provided by separate utility meters.[1] As EV volumes increase, this approach could lead to significant errors in the volume of credits distributed under this pathway.

[1] Source: CARB reported data.

We recommend that CARB utilize vehicle telematics data to accurately and comprehensively measure statewide EV charging. Vehicle manufacturers can accurately report the quantity of electricity consumed by their vehicles by aggregating data recorded and transmitted by on-board vehicle systems. The data captured includes the type of charging (alternating current or direct current), time, and quantity of

electricity (in kWh). These systems are designed to be incredibly accurate given the critical nature of onboard current and voltage sensing for the safe and reliable operation of the charger and battery. In addition to automaker testing of the accuracy of this data, the Environmental Protection Agency (EPA) also tests and confirms the accuracy of this data as a part of its confirmatory testing procedures.

The ability to capture this data is commonplace within the auto industry. In addition to Tesla, we are aware of at least seven other vehicle manufacturers that have this capability, as indicated by their voluntary participation in programs such as the Open Vehicle Grid Integration Protocol.

To encourage EV manufacturers to provide this valuable data, CARB should, at a minimum, permit automakers to receive any additional credits resulting from the comparison of fleet-wide, aggregated vehicle charging with CARB's estimated charging data. For example, if CARB estimates that a given manufacturer's fleet generates 2 credits per vehicle per year, but the automaker's real-world charging data reveals that each vehicle should have generated 2.5 credits, the automaker should be receive the 0.5 credit difference. In the next section of our comments, we make the case for why automakers should receive the entire 2.5 credit allocation, as automakers are best-positioned to utilize the credit value to administer consumer-facing incentives that will increase EV sales in California.

…

Based on the foregoing, we believe CARB should i) permit automakers to earn additional LCFS credits based on actual charging data versus CARB estimates,… (TESLA1_79-2)

Comment: 2. Use of Residential Charging Funds: allow EV manufacturers to opt in and earn base residential charging credits in lieu of utilities for their fleets, as automakers are best-positioned to utilize this value to administer consumer-facing incentives to accelerate zero-emission vehicle deployment in the state.

…

II. Allow EV manufacturers to opt in and earn base residential EV charging credits in lieu of utilities for their fleets, as automakers are best-positioned to utilize this value to administer consumer-facing incentives to accelerate zero-emission vehicle deployment in the state.

There is broad recognition among stakeholders that the rebate programs currently administered by utilities must transition from a fragmented patchwork of post-sale incentives to a statewide, point-of-sale incentive to truly maximize the impact of funds generated under the residential charging pathway of the LCFS. Efficient use of these funds is incredibly important, as the total value generated under the residential pathway exceeded ~$97 million in 2017, which is approaching the total value distributed to non-fuel cell EVs under California's Clean Vehicle Rebate Project (CVRP) over the same period.[2] Automakers have deep experience administering incentive programs to

their customers; and are best-positioned to manage a point-of-sale clean fuels incentive through their network of retail locations. We propose that CARB allow automakers to opt in to the residential charging pathway, provide fleet-wide, aggregated vehicle charging data as the basis for credit generation and deploy statewide point-of-sale incentive programs for their EV products.

[2] Source: CARB reported that ~779k LCFS credits were generated from on-road electricity use in 2017. This equates to ~$97M based on $125/credit. CVRP rebates of $104M were issued to non-fuel cell EVs in 2017. https://cleanvehiclerebate.org/eng/rebate-statistics.

Today, residential charging credits granted to utilities account for the vast majority of on-road electricity credit generation (~93% in 2017).[3] Most of these credits, approximately 80%, are allocated to California's three Investor-Owned Utilities (IOUs) participating in the LCFS.[4] The remaining credits (~20%) are distributed across thirteen Publicly Owned Utilities (POUs). The result is a fragmented network of incentive offerings across the state, where the IOU rebates are the most critical given they receive the bulk of the EV credit value.

[3] Source: CARB reported data. CARB reported that ~779k LCFS credits were generated from on-road electricity use and ~199k from off-road electricity use in 2017.

[4] Source: CVRP reported data, which is used by CARB staff to determine the annual allocation of credits across utility service territories. The three IOUs participating are Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric.

Utility LCFS incentive programs vary in terms of type (e.g. vehicle rebate, charger rebate, electric bill credit, discounted charging rates), amount (e.g. vehicle rebates range from $200-$599, charger rebates vary), eligibility criteria (e.g. anyone who has purchased an EV at any date, customers who purchased an EV in the last 6 months, commercial charger installer) and application process (e.g. one-time rebate check through an online or mail-in form, annual enrollment process for bill credit). Aside from the significant administrative cost required to maintain these programs[5], consumers are rarely aware that these benefits exist when they are making EV purchase decisions, and the programs are too fragmented and time-consuming to explain for automakers to confidently promote them at the point of sale.

[5] The IOUs estimated $6.4M of administrative expense to run their programs in the first two years (2017 and 2018).

We propose that CARB allow automakers to opt in to the residential EV charging pathway and utilize the funds to offer a funded, statewide point-of-sale incentive to their consumers. The point-of-sale approach to incentive design is broadly considered the most effective method of driving EV sales.[6] Below is a summary of the key advantages of automaker-administered incentive programs versus the current utility-administered programs:

[6] "Cash at the time of purchase is by far the best financial incentive – over twice the value of a tax credit." *Evaluating Methods to Encourage Plug-in Electric Vehicle Adoption: A review of reports on PEV incentive effectiveness for California Utilities*, Plug In America for CalETC, p.13 (October 2016). "Of all the options for returning LCFS revenue, a one-time rebate is likely the best means to encourage PEV adoption because it would be provided to all PEV buyers as an up-front amount off the purchase of the EV." *California Public Utility Commission Decision to adopt the LCFS Revenue Allocation Methodology*, p. 30 (December 2014).

Category	Automaker-Administered	Utility-Administered
Incentive Visibility	• Automakers and dealers have natural touch-points with EV consumers at the point of sale, ensuring that every EV buyer is aware of the incentive and receives it	• Current programs are not available at point-of-sale • Consumers are generally unaware that programs exist (Pacific Gas & Electric estimates that only 40% of eligible consumers will sign up for its incentive[7])
Incentive Eligibility	• Incentive available statewide only to *new* customers ensuring incentives actually motivate EV purchase decisions • Automakers have flexibility to determine how to structure their incentives, with a natural motivation to compete with their peers to win EV market share	• Sacramento Municipal Utility District's program allows customers who purchased a vehicle in the last 180 days to apply. Other programs do not have restrictions on when the vehicle was purchased (e.g. consumers who purchased an EV in 2013 can still claim a rebate)
Taxes	• Consumers would receive the incentive at the point of sale and face no tax on the incentive value • Automakers do not have to issue a 1099 tax reporting form to customers	• If utilities provide a rebate ≥$600, they will have to issue a 1099 tax form to consumers, who may then face taxes on the incentive value
Timing	• If modifications are made in this rulemaking, automakers could launch their point-of-sale incentive programs starting in Q1'19	• The timing of when consumers receive the benefits varies depending on the program design (e.g. one-time check provided in the mail or annual bill credit) • Processing times vary by utility as to when consumers will receive a rebate check (weeks or months)
Incentive Value	• Targeting $1,000+ incentive for long-range, 100% Zero Emission Vehicles • Automakers can finance future credit generation to boost near-term incentive values	• Incentives amounts vary (e.g. $200 Pasadena Water & Power, $599 SMUD, SDG&E bill credit ≥ $50) • Charger rebates vary in amount and eligibility
Funding Availability	• Automakers have extensive experience offering incentives to car buyers through their retail networks and can adjust available incentives in real-time to avoid funding gaps • Automakers can bank and trade credits on a monthly or quarterly basis with actual charging data to replenish funds quickly	• Utilities receive credits from CARB on an annual basis; potential for funding gap during the year • Automakers / dealers have no visibility into funding levels, making it challenging to market the rebates to consumers during the sales process
Admin Costs	• Automakers already have the structure to administer statewide vehicle incentives • No incremental marketing expense, as incentives could be advertised in conjunction with general EV advertising and also communicated at the point of sale	• Utilities may incur significant advertising and marketing expenses to promote their programs • The three participating IOUs estimated that they will spend $2.9M in administrative costs in 2018

Data	• Participating automakers will submit aggregated charging data to CARB as the basis for crediting	• The current methodology requires CARB to estimate the amount of residential charging occurring in each utility service territory
Equity	• Automakers can offer a bonus incentive to low-income EV buyers and members of disadvantaged communities • CARB can review and approve automaker program proposals to ensure they address this important component	• The current incentive programs do not include an equity component

[7] *Pacific Gas and Electric Company's 2018 Annual Low Carbon Fuel Standard Credit and Revenue Estimate*, p. 5 (September 2017). https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5150-E.pdf

To administer this proposed approach, CARB would exclude the vehicles manufactured by participating automakers when calculating utility residential credit allocations. This approach does not preclude utilities from continuing their rebate programs, as they could provide incentives for vehicles brands that have not opted in to the residential LCFS pathway.

The proposed change would yield a near-term, statewide and point-of-sale incentive for EV consumers. We urge CARB to implement this change as quickly as possible as consumers will greatly benefit from a clear, consistent and transparent incentive program.

…

Based on the foregoing, we believe CARB should … ii) allow automakers to access base residential pathway credits and administer statewide, point-of-sale incentive programs for EV consumers,… (TESLA1_79-3)

> **Agency Response:** The commenters mention that estimated base credits for residential EV charging assigned to EDUs are based on a small subset of separately metered EV charging data and the individual rebates offered by EDUs are fragmented. The commenters' suggest, therefore, that the base credits should be issued to automakers as they could provide more charging data for residential EV charging and also effectively manage a statewide point-of-purchase rebate program.
>
> Staff agrees that base credits for residential EV charging are estimated based on a small subset of separately metered data provided by the EDUs. However, staff believes currently not all automakers have the capability to collect EV charging data using vehicle telematics and accurately separate the residential and non-residential EV charging data to avoid double counting amongst base credits and non-residential EV charging credits. Moreover, LCFS is a fuels program incentivizing fuel providers supplying alternative transportation fuels to support reduction in carbon intensity of California's transportation fuel pool. EDUs play a critical role and make significant investments in the low-CI electricity generation

resources and in the transmission and distribution networks essential for delivering fuel for EV charging, making them primary fuel providers for residential EV charging. EDUs are also well-positioned to promote the use of electricity as a low carbon transportation fuel by providing better rate options for residential EV charging, adapting and upgrading California's electric grid, and helping support development of EV charging infrastructure. Therefore, staff proposed to keep EDUs as the credit generator for base credits for residential EV charging.

The commenter also suggests that automakers should receive the residential credit because they are in the best position to return the value of the credit to the EV buyer at the point-of-purchase. Since the first Board hearing in April, utilities and automakers have been engaged in ongoing discussions to determine the best utilization of LCFS credit value for residential EV charging, including the development of a statewide point-of-purchase rebate program for EVs. To facilitate a statewide rebate program, staff proposed a few minor modifications to the proposed amendments. One modification would require EDUs to contribute a portion of the base credits or the base credit proceeds to the statewide rebate program should one be established.

In the TESLA1_79-2 comment, the commenter suggests that automakers should be eligible to generate additional base credits if they could demonstrate through telematics data that the quantity of electricity used for charging their EV fleet is higher than the quantity of electricity estimated for calculating base credits. The current methodology for calculating base credits relies on average EV charging rate for all make and models and if the vehicles with higher than average EV charging rate receives additional credits then it would skew the average EV charging rate used for calculating base credits resulting in a potential double counting. Staff believes such a mechanism would introduce complexity for data reporting and validations to ensure no double counting occurs for base credits.

In addition, staff proposed to issue incremental credits for improvement in CI of electricity as compared to the California average grid electricity CI when used for residential EV charging. Any eligible entity that can demonstrate CI improvement of electricity over grid average CI, using book-and-claim accounting for low-CI electricity or using smart charging pathway, could generate incremental credits for the same electricity used for generating residential base credits. Staff believes these credits would provide a strong incentive to promote the use of low-CI electricity for EV charging or shift the EV charging to the times when the marginal CI for grid electricity is low, resulting in additional grid benefits. The proposed incremental credit provisions allows any eligible entities – including but not limited to automakers, CCAs, charging providers, and EDUs – to opt into LCFS program and receive credits for providing low CI electricity for residential EV charging. This means an automaker would be eligible to generate incremental credits for metered residential EV charging if it can meet the proposed FSE registration and reporting requirements.

In response to commenter's suggestion in JLRNA1_44-2 that EV manufacturers should be allowed to claim non-residential EV charging credits, staff would like to note that owner of the Fueling Supply Equipment (FSE) is the primary fuel provider for non-residential EV charging as it is the one investing in development and maintenance of the charging infrastructure necessary for the EV charging. Therefore, staff proposed the owner of the FSE or its designee would be the credit generator for non-residential EV charging as long as it can meet the proposed FSE registration and reporting requirements. This means an EV manufacturer would be eligible to generate credits for the non-residential EV charging as long it is the owner or designee for the FSE and it meets the proposed FSE registration and reporting requirements.

D-6.24b. Comment: Some EV manufacturers, notably Tesla, have proposed a model in which unmetered household charging credits are assigned to vehicle manufacturers at the time of sale and the value of those credits are converted into a rebate by the manufacturer. Such a program must be carefully designed to ensure that the interests of Californians, including current EV owners, prospective EV owners and utility customers are protected. (NEXTGEN1_124-34)

Agency Response: Staff appreciates the commenter's concern about designing rebate programs where base credits are assigned to EV manufactures. Staff proposed to keep Electric Distribution Utilities (EDU), or a designee, as the sole credit generator for base credits for residential EV charging. The automakers would be eligible to opt into the program and generate incremental credits for EV charging and would be required to meet the requirements set forth in section 95491(d)(A)7.

D-6.25. *Statewide Point-of-Purchase Rebate Program*

D-6.25a. Multiple Comments: *General Support for a Statewide Point-of-Purchase Rebate Program*

Comment: 4. ARB should work to develop and implement an EV credit program that is state-wide, consistent, and that results in an upfront "clean fuels reward" for EV customers toward the purchase or lease of an electric vehicle or charging infrastructure.

NRDC supported the development of regulatory principles early-on in the development of the LCFS to help ensure that parties receiving EV LCFS credits would ultimately use proceeds to benefit current and future EV customers making the switch to clean electricity. NRDC agrees with utilities, NGOs, and automakers that six years later, the program could improve its efficacy and effectiveness in terms of expanding the EV transportation market. At the same time, we are cognizant that regulated parties have already established programs that are in place and that EV customers are starting to receive benefits. We ask the Board to direct ARB staff to develop a solution that captures the input from utilities, automakers, charging service providers, and NGOs in a timely, deadline-driven manner that meets the following objectives.

- Point-of-sale, clean fuels reward:
    - LCFS credits generated should go to increasing customer adoption of electric vehicles (passenger vehicles, trucks, buses, goods movement vehicles) to increase the use of electricity as a clean fuel.
    - Based on their express choice, EV customers should be able to select either a lump sum “clean fuels reward” that could go towards the purchase or lease of an electric vehicle or the purchase of charging infrastructure, ideally provided at the point-of-sale.
- State-wide consistency and reach
    - The clean fuels reward program should work the same for all California EV customers across utility boundaries and apply to all automakers selling electric vehicles. Additional state-, utility-, or automaker-specific programs could still be layered upon the baseline LCFS reward. But at its core, the LCFS clean fuels reward program should be well advertised, transparent, and easy to understand.
- Increased fairness
    - The amount of EV reward should correspond with the expected electric miles traveled or, more accurately, the GHG emissions avoided from that electric vehicle model based on the footprint. ARB should simply provide a table for the reward amounts that models would receive so that a 240-mile EV is credited fairly versus a 15-mile plug-in hybrid, for example.
    - The clean fuels reward should also encourage increased EV access and affordability in low-income, disadvantaged communities
- Higher-impact
    - The LCFS clean fuels reward should be supportive of regulated entities bringing the stream of credit value up-front (i.e. providing 3+ years of credit value).
    - ARB could consider allowing a “LCFS balancing account” to be used for electricity that have a very-high likelihood for future credit generation. ARB could consign three years or more of credit generation to the EV regulated entity at a discounted amount, with those regulated entities in turn agreeing to have future credits retired. (NRDC1_81-11)

Comment: We encourage CARB to expeditiously move forward proposals that ensure the use of credits generated from residential EV charging accelerate EV sales – in particular moving toward point of sale rebates to more effectively influence purchase decisions.

…

Improving electric vehicle crediting

We encourage CARB to reconsider whether the current programs established by utilities to rebate LCFS credit value to EV drivers are most effectively supporting the expansion of this low carbon fuel pathway. A uniform state-wide approach that makes LCFS credit value available at point of sale could be more effective at increasing EV sales, and thus expanding the use of this low carbon fuel pathway. We encourage CARB to expeditiously move forward proposals that improve the use of credits generated from residential EV charging to accelerate EV sales. (UCS1_53-5)

Comment: Third, we encourage CARB to expeditiously move forward proposals that ensure the use of credits generated from residential EV charging better facilitate EV sales, particularly moving toward point-of-sale rebates to more effectively influence purchase decisions. (UCS2_T53-5)

Comment: SCE's program to return LCFS credits to residential EV owners (Clean Fuel Rewards) began less than 12 months ago, as did similar programs by other investor-owned utilities. SCE's program was designed when LCFS credit prices were approximately six times less than today's LCFS credit prices. As a result, SCE recognizes that its program needs to be updated. SCE also wants to explore a point-of-sale rebate in order to encourage EV adoption, augment CARB's existing Clean Vehicle Rebate Program (CVRP), and engage car dealers of new and used EVs[3] so they could provide a "one-stop shop" to sign up EV buyers for the various EV incentives, including off-peak charging rates from utilities.

[3] In a mature market used car sales are 2.5 times more each year than new car sales. According to Bloomberg, 80% of battery EVs and 50% of plug-in hybrid EVs have 2 or 3 year leases, which brings EVs to the used market much faster than with gasoline cars.

Off-peak charging can save EV owners who charge at home over $5,000 during the life of the EV.[4] But first, the EV owner must think to contact their utility instead of relying on the owner's existing residential rates.[5] LCFS-funded rebates can be the attention-grabber that enables customers to sign-up for attractive off-peak rates.

[4] Compared to driving on gasoline.

[5] SCE has offered TOU rates designed to encourage EV adoption at homes and businesses for over 20 years, including whole house TOU rates that don't require a separate meter. We expect new, very attractive TOU rates for businesses and optional whole house TOU rates designed for EVs to be in effect in early 2019. Currently, most EV buyers don't contact SCE about their car purchase, so we can't easily get them on rates designed for EVs or log this information to assist with future distribution grid planning. LCFS programs can help address these and many other impediments to EV adoption.

<u>SCE is open to modifying how the utilities' LCFS credit proceeds from residential charging are distributed as part of a CARB-led process involving utilities, automakers and other stakeholders.</u> SCE does not believe a major change in the design of base residential LCFS credit provisions should be made as part of the 15-day change process. The subject is very complicated, and would benefit first from fuller discussion, debate and evaluation in an engaged stakeholder process. Regulatory changes could then be brought to the CARB Board in early 2019 if the CARB-led stakeholder process deemed that to be necessary. (SCE1_108-3)

Comment: *NextGen Supports Using LCFS Credit Value to Provide Point-of-Sale ZEV Rebates*

As the Cerulogy research demonstrated, ZEVs, especially battery electric and plug-in hybrid vehicles, are a key part of California's long-term sustainable transportation future. The primary limiting factor on their total contribution towards attaining the state's climate and clean air goals is rapid deployment. Sales will need to rapidly expand in order to meet the 5 million ZEV target from Executive Order B-48-18. Rebates are a key tool to drive early sales and have significantly contributed to ZEVs rapid growth from essentially zero a decade ago to over one percent of new car sales.

At present, the LCFS supports several rebate programs offered through utilities. LCFS credits from un-metered household charging are transferred to utilities, who are required to use the revenue to support the continued expansion of the electric vehicle market. Many offer rebates to EV owners, though these rebates may not be received by the purchaser until weeks or months after the vehicle is purchased. Owners cannot currently determine their eligibility for rebates at the time and place of sale; they must either apply after they purchase the car and risk being denied a rebate, or they must pre-qualify for a rebate under a program recently developed by the CVRP administrator. Pre-qualification must occur several days in advance of purchase, which presents a significant procedural hurdle for potential buyers and does not align well with the dynamic, incentive-based sales approach of most auto dealers. Lower-income purchasers are particularly affected, as they may lack the funds to pay a higher price for a vehicle and wait for a rebate.

The solution is a point-of-sale rebate, which can be deducted from the purchase price, with the rebate being seamlessly conveyed to the dealer. **NextGen strongly supports efforts to develop a point-of-sale rebate funded by revenue from un-metered residential charging LCFS credits.** Point-of-sale rebates are widely understood to be more effective at driving consumer behavior and a rebate of this type would more effectively support existing State efforts to accelerate the penetration of ZEVs into the market. A point-of-sale rebate would almost certainly deliver more value to the state than the current slate of utility-sponsored rebate programs. (NEXTGEN1_124-33)

Comment: We hasten to add that for the foreseeable future, any use of LCFS credits for vehicle point-of-sale should be done to augment, and not replace, the current CVRP program, or funding sources for it. Vehicle incentives are badly under-resourced and are in need of a stable multi-annual allocation that is additional to a more optimized use of LCFS credits. (CALSTART1_B6-5)

Comment: Second thing is on the -- just the notion of a point of sale and packaging the LCFS stream so you get more of a benefit from the point of sale is the first incentive. We support that very much in concept and look forward to working with automakers and utilities in the coming months and year to make that work and turn it into something that optimizes further the LCFS credits.

But we just want to make sure it's clear that that funding should not be considered as replacing the CVRP or GGRF funding, that the program is underfunded and we need additional support. So this is something that's separate. (CALSTART2_T13-3)

Comment: And also we'll echo the support for the Board moving and looking for ways to move towards a point of sale for our zero-emission vehicles, to help advance that fleet, bring consumers closer to the point of incentive funding when they're making their vehicle choices. (HMO2_T15-5)

Comment: And lastly, I'll say I also support Low Carbon Fuel Standard credits being available at the point of sale, especially in disadvantaged communities with low-income residents having that incentive available at the point of sale and -- is great, so people who don't have the funding to weight for a rebate, they could use it right then in the moment. (CVAQ2_T46-2)

Comment: We also very much support a point of sale statewide rebate funded through the LCFS credit -- base credit value. And we are going to work with our partners in the auto industry. This is not -- I totally agree with Tesla, this is not an automaker versus utility issue. This is an automaker and utility issue, as well as dealerships, and other stakeholders.

So this doesn't require any modification to the regulation. We can work collaboratively together and make this happen and we're committed to doing that. (UTILITIES1_T47-5)

Comment: This Board, and the legislature, and the Governor have all established very aggressive zero-emission vehicle goals ranging from a million vehicles in 2023 all the way up to four to five million zero-emission vehicles by 2030.

For our part, for the manufacturers' part, they currently offer over 40 ZEV models. And over the last eight months, virtually every major car company has announced auto electrification pans that will more than double those ZEV models.

So -- and those vehicles come in every shape and size from small car to large car, SUV to minivan, short range to long range, economy to luxury two-wheel drive to all-wheel drive.

In total, by 2025, automakers are likely to invest in excess of $100 billion on ZEV research, development, production, and promotion. So I say that to say this, that if we fail to meet our targets, it will not be because of a lack of effort, or a lack of investment by the automakers. It will not be because of a lack of ZEV models. It will be because we collectively have failed to properly build the complementary measures, such as incentives, infrastructure, low and simple – low-cost fuels and simple fuel cost, and consumer awareness.

The LCFS Program offers a tremendous opportunity to invest in this, and to support the ZEV market. However, today, the LCFS Program, as it relates to ZEVs, is kind of languished, and it's not being used as effectively as it could be.

For example, each utility offers a different rebate program, some high, some low, but generally lower than what we would expect. Each utility offers a different way to apply for it and a different mechanism for doing that.

So our goal, and I think ours collectively, is to provide the biggest acceleration for the ZEV market. And the Alliance, our members, we propose working with staff, the other automakers, utilities to develop a program that will provide the best acceleration of the ZEV market.

And one possibility is as several have said is larger, more representative statewide rebates that are applied at the point of sale, but I'm sure there are other ideas. (AAM1_T54-1)

Comment: Back on the ground, we believe that all of the value of LCFS credits for residential electric vehicles should be used to benefit EV drivers. One of the best ways to put some of that credit value to work would be through a statewide point of incentive for new EV buyers. Such an incentive would support the governor's goal of putting 1.5 million ZEVs on our roads by 2025 and 5 million by 2030.

Point-of-sale incentives are the most effective way of putting a car buyer behind the wheel of a new ZEV. Yet the current program does not take full advantage of this powerful tool.

Under the current program consumers shopping for a new car might not be aware of available incentives offered by their local utility for the purchase of an EV, and that certainly is a lost opportunity.

Or a rebate might be offered long after the purchase, which would effectively obscure the buyer's motivation for going electric.

With a point-of-sale incentive the buyer is either made aware of the incentive at the dealership or beforehand through marketing and advertising. Consumer benefits and program improvements would include a reduction in the point-of-sale purchase price of an EV. Automakers would generate credits based on actual charging data, an improvement over the current estimate methodology.

Qualified buyers in low-income and is advantaged communities would more likely consider the purchase of an EV with a point-of-sale incentive. (CCA2_T12-4)

Comment: A number of stakeholders have raised interesting questions about who should get the credits, how the program should most effectively support the development of a sustainable market. It may be that a much larger point-of-sale rebate is the way to go, but there are multiple ways to do this and there are a lot of tricky implementation questions to work through. (GM1_T49-3)

> **Agency Response:** Staff appreciates the commenters' support for a statewide point-of-purchase rebate program to promote ZEV adoption. While the existing utility rebate programs funded by LCFS are helpful in promoting electricity as a low carbon fuel, they could be improved with better coordination among utility across service territories. Since the first Board hearing in April, utilities and automakers have been engaged in ongoing discussions to determine the best

utilization of LCFS credit value for residential EV charging, including the development of a statewide point-of-purchase rebate program for EVs.

A statewide rebate program would allow the utilities to work together to establish a consistent statewide rebate available to all EV buyers providing a stronger signal to promote EV adoption while sharing the associated administrative and marketing costs. Staff believes, and as expressed in the comments, a point-of-purchase rebate may be more effective in determining consumer choice than the incentives that are not available at the point when buyer is making the purchase decision. Further, joint efforts by utilities, automakers, and dealerships would provide better opportunities to outreach and educate customers about the benefits of EVs and potentially provide option to enroll into available time-variant rates for EV charging.

Board Resolution 18-17 directed the Executive Officer to explore with stakeholders the opportunities to increase the magnitude of ZEV vehicle rebates funded by sale of LCFS credits. The Board direction also asked to focus on the possibility of creating a statewide point of sale or point-of-purchase rebate for vehicles, and explore synergies with other rebate programs.

In response to Board direction, staff proposed changes to facilitate a statewide rebate program that would streamline the LCFS incentives by creating a standard point-of-purchase rebate available for all EV buyers across California. Staff believes it would be valuable to promote plug-in electric vehicles with greater all-electric range and larger battery packs, so the incentive can help advance battery technology in-line with the technology advancement goals of the LCFS. So far, the existing utility rebate programs have not differentiated by EV's rated battery capacity and staff believe this is a missed opportunity to promote costs decline in EV battery technology. Therefore, staff proposed the statewide rebate must mirror the structure of Plug-In Electric Drive Vehicle Credit also known as the federal EV tax credit, which is a sliding scale based on the rated battery capacity of EV. This structure is well understood by the auto dealers and a statewide rebate program based on the same principal could be easily integrated to the EV sales pitch and marketing materials.

The proposed statewide rebate would be funded by the LCFS credit proceeds and would complement other rebates funded by Clean Vehicle Rebate Project (CVRP), Greenhouse Gas Reduction Fund (GGRF) or other state funding.

In regards to equity component in the rebate program, the Board resolution 18-34 directed Executive Officer to work with stakeholders to establish an equity-based framework for the possible uses of base credit value from residential charging, consistent with legislative priorities. Board also directed to continually evaluate such provisions and propose adjustments as needed. Staff did not propose any specific provisions or measure to address equity in the regulation as it intends to engage and draw inputs from all the relevant stakeholders for developing a

comprehensive equity-based framework for the incentive programs funded by the base credits.

In further response to NRDC1_81-11 where commenter is suggesting to front load credits for future years, staff did not propose to issue credits in advance for reductions that are anticipated in future years. However, staff did clarify that the rule does not preclude contracting for future delivery of LCFS credits which would provide entities option to enter into long-term contracts to secure stable funding for a rebate program.

D-6.25b. ***Recommendations for a Statewide Point-of-Purchase Rebate Program Managed by EV Manufacturers***

Comment: *LCFS Credit Revenue Must be Predominantly Used to Support EV Deployment*

Concepts for a LCFS-funded rebate program that have been put forward by EV manufacturers often indicate that they will recover administrative and financial costs from the LCFS revenue, including the cost of capital needed to convert ongoing streams of LCFS credit revenue into up-front rebates and a risk premium to reflect policy or market risks. We recognize the need for manufacturers to cover administrative costs and agree that a reasonable risk premium is warranted given the uncertainty surrounding any climate policy instrument. Manufacturers should not, however, routinely make substantial profit on the administration of a program meant to dispose of policy instruments which support a public good, clean air. Manufacturers will have ample opportunity to derive profit from increased sales of their product. If the cost and risk involved in managing a rebate program is too great for them to bear, there are several non-profit organizations with deep expertise in managing rebate programs which could do so.

To this end, any organization which seeks to receive LCFS credits for the purpose of providing a point-of-sale rebate must provide a transparent proposal for administering the program for CARB and allow for public review. This must include:

- A clear indication of both expected revenue and expenditure
- A verifiable plan of action to cover the possibility that LCFS credit prices will be above plan assumptions, resulting in more revenue than anticipated.
- Clear identification of any administrative costs, financing costs, risk premiums or other revenue which will not directly go towards ZEV deployment
- Demonstrated technical capacity to assess the number of LCFS credits generated by the charging of the vehicles for which LCFS credits will be assigned to the manufacturer.
- Demonstrated technical capacity to exclude charging at public, commercial, or independently-metered charging stations from the assessment of total LCFS

credit assignment. Credits from these stations shall remain with the station operator, as under the current LCFS protocol.

- Regularly scheduled reviews to demonstrate that the program is actually performing in line with expectations.
- A commitment to allow an independent audit at CARB's discretion

We also strongly recommend that if CARB chooses to develop a LCFS-funded point-of-sale rebate protocol along the lines proposed by EV manufacturers, they do so with the consent of utilities who currently administer programs to use unmetered residential charging credits. We appreciate auto manufacturer's interest in developing an effective rebate program, and believe it will be most successful if implemented with the cooperation of utilities and with robust oversight. (NEXTGEN1_124-35)

Agency Response: The commenter suggests to include several checks and measures if the EV automakers are assigned base credits for administering a statewide point-of-purchase rebate program. Staff believes automakers have a critical role to play in supporting the ZEV adoption in the state; however, utilities are well-positioned to promote use of electricity as a transportation fuel. Further, to facilitate a rebate program funded by LCFS credits that is managed by automakers, significant changes would be required to the LCFS regulation which staff believe are unnecessary to effectively utilize LCFS incentives to promote ZEV adoption. Therefore, staff proposed the utilities continue to receive base credits and proposed a few minor modifications to facilitate administering a statewide point-of-purchase rebate program.

Since the first Board hearing in April, utilities and automakers have been engaged in ongoing discussions to determine the best utilization of LCFS credit value for residential EV charging, including the development of a statewide point-of-purchase rebate program for EVs.

As proposed by the staff, the opt-in utilities are required to use all credit proceeds to benefit current or future EV drivers or customers in California and educate them about the benefits of EV transportation. In addition, opt-in utilities are required to provide an annual summary of efforts and costs involved associated with meeting the above requirements. The statewide rebate program could be managed directly by the utilities or by a third-party administrator hired by the utilities which would be subject to the same requirements.

The staff retains the ability to request more information to audit and assess the success of rebate programs funded by LCFS proceeds.

D-6.25c. Multiple Comments: ***Support Statewide Point-of-Purchase Rebate Program Managed by EV Manufacturers***

Comment: We support the current proposal to create a statewide point-of-sale incentive for new EV buyers, particularly low to mid-income households, which would be

administered by EV manufacturers, subject to approval by CARB, based on residential charging data recorded by the vehicles. EV manufacturers are well-positioned to effectively market and administer a statewide point-of-sale rebate program given their natural touchpoints with consumers in their showrooms and dealerships. Under this proposal, EV manufacturers would opt-in to the residential electricity pathway for their vehicles and present a plan to CARB for approval regarding how the funds would be spent to drive EV adoption in California.[1] Utilities could continue to administer their rebate programs for vehicle manufacturers that do not participate in the program.

[1] Stakeholders broadly accept that point-of-sale incentives are the most effective for driving consumer EV adoption. "Cash at the time of purchase is by far the best financial incentive – over twice the value of a tax credit." *Evaluating Methods to Encourage Plug-in Electric Vehicle Adoption: A review of reports on PEV incentive effectiveness for California Utilities*, Plug In America for CalETC, p.13 (October 2016). "Of all the options for returning LCFS revenue, a one-time rebate is likely the best means to encourage PEV adoption because it would be provided to all PEV buyers as an up-front amount off the purchase of the EV." *California Public Utility Commission Decision to adopt the LCFS Revenue Allocation Methodology*, p. 30 (December 2014).

This approach provides significant consumer benefits and improves upon the existing program design:

- Automakers can market the incentive to all California EV buyers. This improves upon the current program design, which has resulted in a fragmented portfolio of incentives based on utility territory.
- The incentive would reduce the upfront cost of EVs at the point-of-sale, ensuring that funds are effectively deployed to motivate sustainable purchase decisions. In contrast, under the current program design, potential EV buyers may not be aware of available incentives in their utility territory when considering an EV purchase. Furthermore, current programs allow consumers to apply for rebates long after their purchase decisions were made, making it unclear whether the rebate funds were ever a driving factor in the decision to go electric.
- Automakers would generate credits based on actual charging data versus estimates, which is the current program methodology. This enhances the integrity of the program and addresses some of the concerns raised by obligated parties.
- Automakers should support EV adoption in low-income or disadvantaged communities by offering an additional incentive to qualifying buyers. CARB should work closely with automakers to create these additional incentives." (BDP1_1-1)

Comment: We support the current proposal to create a statewide point-of-sale incentive for new EV buyers, which would be administered by EV manufacturers, subject to approval by CARB, based on residential charging data recorded by the vehicles. EV manufacturers are well-positioned to effectively market and administer a statewide point-of-sale rebate program given their natural touchpoints with consumers in their showrooms and dealerships. Under this proposal, EV manufacturers would opt-in to the residential electricity pathway for their vehicles and present a plan to CARB for approval regarding how the funds would be spent to drive EV adoption in California.[1]

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- Automakers would generate credits based on actual charging data versus estimates, which is the current program methodology. This enhances the integrity of the program and addresses some of the concerns raised by obligated parties.
- Automakers can support EV adoption in low-income or disadvantaged communities by offering an additional incentive to qualifying buyers. (CULTURA1_15-1, WM1_83-1)

Comment: We support the current proposal to create a statewide point-of-sale incentive for new EV buyers, which would be administered by EV manufacturers, subject to approval by CARB, based on residential charging data recorded by the vehicles. EV manufacturers are well-positioned to effectively market and administer a statewide point-of-sale rebate program given their natural touchpoints with consumers in their showrooms and dealerships.

Under this proposal, EV manufacturers would opt-in to the residential electricity pathway for their vehicles and present a plan to CARB for approval regarding how the funds would be spent to drive EV adoption in California.[1] Utilities could continue to administer their rebate programs for vehicle manufacturers that do not participate in the program.

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- Automakers would generate credits based on actual charging data versus estimates, which is the current program methodology. This enhances the integrity of the program and addresses some of the concerns raised by obligated parties.
- Automakers can support EV adoption in low-income or disadvantaged communities by offering an additional incentive to qualifying buyers. (CVAQ1_43-2)

Comment: We support the current proposal to create a statewide point-of-sale incentive for new EV buyers, particularly low to mid-income households, which would be administered by EV manufacturers, subject to approval by CARB, based on residential charging data recorded by the vehicles. EV manufacturers are well-positioned to effectively market and administer a statewide point-of-sale rebate program given their natural touchpoints with consumers in their showrooms and dealerships. Under this proposal, EV manufacturers would opt-in to the residential electricity pathway for their vehicles and present a plan to CARB for approval regarding how the funds would be spent to drive EV adoption in California.[1] Utilities could continue to administer their rebate programs for vehicle manufacturers that do not participate in the program.

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- Automakers would generate credits based on actual charging data versus estimates, which is the current program methodology. This enhances the integrity of the program and addresses some of the concerns raised by obligated parties.
- Automakers can support EV adoption in low-income or disadvantaged communities by offering an additional incentive to qualifying buyers. (ARIA1_98-2)

Comment: The electricity pathway within the LCFS is an important tool to support the Governor's goals of placing more than 1.5 million Zero-Emission Vehicles (ZEVs) on California roads by 2025 and 5 million by 2030. But the current program does not fully utilize the LCFS' potential to create incentives for the purchase of ZEVs. We support the creation a statewide point-of-sale incentive for new EV buyers, which would be administered by EV manufacturers, subject to approval by CARB, based on residential charging data recorded by the vehicles. Point-of-sale incentives are the most effective way to drive consumer ZEV adoption, especially for non-affluent buyers.

This approach provides significant consumer benefits and improves upon the existing program design:

- Automakers can market the incentive to all California EV buyers. This improves upon the current program design, which has resulted in a fragmented portfolio of incentives based on utility territory.
- The incentive would reduce the upfront cost of EVs at the point-of-sale, ensuring that funds are effectively deployed to motivate sustainable purchase decisions. In contrast, under the current program design, potential EV buyers may not be aware of available incentives in their utility territory when considering an EV purchase. Furthermore, current programs allow consumers to apply for rebates long after their purchase decisions were made, making it unclear whether the rebate funds were ever a driving factor in the decision to go electric.

- Automakers would generate credits based on actual charging data versus estimates, which is the current program methodology. This enhances the integrity of the program and addresses some of the concerns raised by obligated parties.
- Automakers can support EV adoption in low-income or disadvantaged communities by offering an additional incentive to qualifying buyers. (CCA1_52-4)

Comment: Further, we continue to support programs that provide direct consumer rebates for zero emission vehicle credits generated under the LCFS. While these programs allow consumers to submit a request for rebate after purchasing a vehicle based on estimated zero emission fuel use, we encourage CARB to also consider the establishment of a pathway that would allow consumers to receive a rebate at the time of the vehicle purchase. This could be accomplished on a voluntary basis with zero emission vehicle makers opting to provide a rebate and submitting real-world charging data related to vehicle use. By aligning the rebate with real-world charging information, as well as vehicle type, the consumer could receive a clearer signal as to the benefits of their vehicle choices. (VB1_10-4, HMO1_113-4)

Comment: Automakers are ideally placed to acquire and report accurate and verifiable EV charging records, including Time-of-Use. EV manufacturers are also best placed to use the credit proceeds to further the advancement of electrification including at the point of sale, at charging stations, through private-private and private-public partnerships. Credit proceeds would also be used to promote greater electric vehicle miles driven by plug in hybrids through innovative financial and smart charging incentives. (JLRNA1_44-3)

Comment: One of the most important fuels in California for the long-term reduction of emissions from the transportation sector is electricity. For this reason, and to meet the Governor's goals of 1.5 million electric vehicles (EVs) on California roads by 2025 and 5 million by 2030, it is imperative that the LCFS properly rewards the use of electricity in the program. In short, the LCFS should establish well-crafted market signals that inspire maximum investment in and adoption of EVs – with particular emphasis on incentivizing charging EVs with renewable energy. For this reason, EDF supports the proposal to create a statewide point-of-sale incentive for new EV buyers, which would be administered by EV manufacturers and based on residential charging data recorded by the vehicles.

…

With regard to the point-of-sale proposal, EDF believes that EV manufacturers are well-positioned to effectively market and administer such a program given their natural touchpoints with consumers in their showrooms and dealerships. While utilities should continue to administer their rebate programs for vehicle manufacturers that do not participate in the program, it is important to minimize artificial barriers to customer entry and seek out opportunities to ensure consumers are fully educated about rebates and

incentives during the vehicle buying process. Furthermore, as compared to the current program design which uses estimated electricity use volumes, moving the LCFS to a program that uses actual charging data enhances the integrity of the program overall and addresses some of the concerns raised by obligated parties. (EDF1_48-5)

Comment: Ford recommends that California consider amendments to the LCFS program allowing for the inclusion of EV manufacturer participation and multiple forms of incentive offered to the consumer at point of sale.

…

Ford believes that EV manufacturers are well positioned to assist in increasing the effectiveness of the LCFS program given their natural relationships with customers and their vehicles. Ford is supportive of Point-of-Sale (POS) incentives to help spur greater EV adoption and we believe that there is a range of different POS approaches that should be considered, in addition to rebates for the vehicle itself. There are a variety of ways that the credit value can be returned to the customer at POS which can offer the consumer broader choice and prove to be more holistically effective. Ford would be eager for the opportunity to discuss these further with CARB, as we recognize that many details of the mechanism need to be discussed and decided.

In summary, Ford recommends that California consider amendments to the LCFS program allowing for the inclusion of EV manufacturer participation and multiple forms of incentive offered to the consumer at point of sale. (FORD1_58-1)

Comment: As it relates to the rebate program that's currently available and administered through California utilities, we believe that improvements should be made urgently to the rebate program. Specifically, these rebates should be available at the point of sale. We think that the rebates should be available statewide regardless of which utility territory you're in. And we think it should be clear and simple enough that a consumer and frankly a salesperson can easily explain it to a customer and the customer can really appreciate and understand the value as they're making that critical decision to go electric.

This is not a situation where it's like the automakers versus the utilities battle of the ages type of thing. But we have submitted comments saying that we think the automakers, given our natural touchpoint with the consumers at the point of sale, could easily step in and help CARB improve the effectiveness of this pathway by administering that directly as an automaker. So that's something we hope the Board would consider.

Lastly -- and just sort of finishing up on that note, we would also bring to the table real data from the car -- recorded from the cars that would help CARB move away from a situation where you actually have to estimate how much charging is happening when you generate these credits. But we could actually use data from the vehicles themselves and give you some real quality backdrop to the credits that are being generated.

So that's some more value we think we can add as an automaker. (TESLA2_T26-5)

Agency Response: Staff appreciates the commenters' support for a statewide point-of-purchase rebate program. The commenters' also proposed such a statewide program would be better managed by automakers. Staff believes automakers have a critical role to play in supporting the ZEV adoption in the state; however, utilities are well-positioned to promote use of electricity as a transportation fuel. Further, to facilitate a rebate program funded by LCFS credits that is managed by automakers, significant changes would be required to the LCFS regulation which staff believe are unnecessary to effectively utilize LCFS incentives to promote ZEV adoption.

Staff believes utilities are better suited to support EV adoption in disadvantaged and low-income communities. In fact, utilities are already supporting programs focused on disadvantaged communities including vehicle or charger rebates, investment in multi-family and public charging infrastructure, rate options for EV charging, and support variety of customer education and awareness programs.

Since the first Board hearing in April, utilities and automakers have been engaged in ongoing discussions to determine the best utilization of LCFS credit value for residential EV charging, including the development of a statewide point-of-purchase rebate program for EVs.

In response to the comments related to the existing utility rebate programs funded by LCFS, please refer to Response D-6.25a, General Support for a Statewide Point-of-Purchase Rebate Program, in this chapter.

In response to comments suggesting automakers could generate credits for residential EV charging based on actual charging data, please refer to Response D-6.24a in this chapter.

D-6.25d. ***Suggestions for Statewide Point-of-Purchase Rebate Program***

Comment: *A Possible Alternative to a Manufacturer-Administered Program*

We intend to continue working with stakeholders to develop a mutually agreeable solution by which LCFS credits could be used to fund a point-of-sale ZEV rebate. Designing a manufacturer-based program is complex and requires coordination by a broad variety of stakeholders. It may not be practicable to do so under the timeline of the current rulemaking. In that event, we **suggest that CARB allow owners to assign unmetered residential charging LCFS credits to the organization or recipient of their choice at the time of sale.** We suggest that CARB retain a role in approving programs that are eligible for assignment, using criteria similar to existing provisions regarding utility use of LCFS credit revenue.

This would allow manufacturers, auto dealers, financial institutions and other stakeholders to offer a range of rebate options at the time of sale. In practice, these could be provided as a point-of-sale rebate by contractual agreement between the entity offering the rebate and the dealer. We anticipate that under this model, manufacturers

would be well-positioned to offer rebates like those proposed by Tesla and other manufacturers.

Allowing assignment of unmetered charging credits allows institutions to experiment with various models of financing and rebates without having to seek regulatory approval for each modification to the program. It is entirely possible that this change alone could facilitate a broad transition to a system much like that proposed by manufacturers, without the State having to unilaterally decide upon that as the solution. (NEXTGEN1_124-36)

> **Agency Response:** Staff appreciates the commenters' suggestions but believes EDUs are the primary fuel provider for residential EV charging given their role in developing low-CI electricity generation resources and maintaining transmission and distribution networks essential for delivering fuel for EV charging. Therefore, staff proposed the base credits for non-metered residential EV charging are estimated and issued to the opt-in EDUs based on the best available data about average EV charging rate and the EV population in each EDU service territories.
>
> Providing the owner or the lessee an option to assign base credits for residential charging associated with their EV would require significant outreach efforts to educate individual EV drivers about the program and manage an extremely large database of assigned credit generators for each EV in California. This could potentially risk double counting or underestimation of residential base credits. Moreover, as per the commenter's recommendation, third parties could be assigned rights to generate residential base credits if they can provide accurate records of EV charging. However, only a small portion of residential EV charging is metered. Staff believes the proposed approach would add complexity and could be disruptive for the implementation of statewide rebate program managed by utilities.

D-6.25e. Multiple Comments: ***Role of Public Utilities in Promoting Electricity as a Transportation Fuel in California***

Comment: Program Goal: Transportation Electrification in Disadvantaged Communities

SB 350 requires that larger publicly owned utilities (POUs) each adopt an integrated resource plan (IRP) to "minimize localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities".[1] In addition, Governor Brown's Executive Order B-48-18[2] stipulates the goal of "250,000 zero-emission vehicle chargers, including 10,000 direct current fast chargers, by 2025."

[1] Public Utilities Code Section 454.52 (a)(1)(H) and Section 9621 (b)(3).

[2] https://www.gov.ca.gov/2018/01/26/governor-brown-takes-action-to-increase-zero-emission-vehiclesfund-new-climate-investments/

APU and RPU are both owned by and directly accountable to the people and businesses that they serve, and are proud of the critical and direct role they play in local communities. Roughly half of both APU and RPU service territories are comprised of

low income and disadvantaged communities,[3] many of which are located along highway corridors and in high-density housing neighborhoods.

[3] APU's low income and disadvantaged communities include communities designated by CalEPA using the California Communities Environmental Health Screening Tool ("CalEnviroScreen") and Community Development Block Grant (CDBG) eligible areas as defined by the Department of Housing and Urban Development.

In early 2017, APU launched a city-wide customer survey as part of its IRP community outreach efforts to obtain customer input on APU's IRP objectives. As part of the survey, customers were asked for their opinions on local air quality. According to the responses received, lower income customers gave lower ratings on air quality, and attributed local air pollution mainly to mobile sources. Indeed, many of APU's low income and disadvantaged customer neighborhoods lie along transportation corridors. The survey also concluded that renters are as likely to own EVs as homeowners are, and that access to public charging would greatly motivate EV ownership. This customer feedback validates APU's decision to support transportation electrification through the deployment of publicly accessible EV charging infrastructure throughout its service territory.

RPU is in the process of developing programs to incentivize EV ownership. Like most Southern California cities, many of our customers commute to other locations for work and other reasons; and, Riverside is a destination for many universities and schools as well as hosting several large employers, including County and Federal courts and other offices. Expanding EV infrastructure to support EVs is as important as incentivizing customers to own or lease EVs.

APU and RPU believe that POUs are uniquely positioned to address the needs of customers within their service territories, which in APU's case includes planning and implementing publicly accessible EV charging infrastructure to benefit all customers. Limiting or reducing the POUs' uses of proceeds from LCFS credit sales to specific programs will not further or encourage POU participation in the LCFS Program. (ARPU1_42-2)

Comment: Highlighting APU's Successful Program Implementation

Since the inception of APU's Public Access EV Charging Station Rebate Program, 21 publicly accessible EV charging stations have been installed and 138 more are expected to be installed by the end of 2018. As of December 2017, 193 public access charging stations are located within APU service territory,[4] of which, 90% are located in low income or disadvantaged communities.

[4] U.S. Department of Energy's Alternative Fuels Data Center, http://www.afdc.energy.gov/data_download, December 20, 2017.

APU's Public Access EV Charging Station Rebate Program is working successfully for the benefit of Anaheim's residents and businesses. The funding received from the sale of LCFS credits is vital to keeping this program available to APU's customers; as the proceeds from the sale of LCFS credits is the primary funding source of the program.

Most importantly, any regulatory requirements that remove or redirect how this funding must be spent would be detrimental to this successful program.

In addition, APU believes the Board's support of the Public Access EV Charging Station Rebate Program will encourage other non-participating POUs to consider becoming LCFS Credit Generators,[5] since the program allows POUs to focus on local communities and build on utility core strengths, including providing electricity as the cleaner, alternative transportation fuel.

[5] Proposed Amendments to the Low Carbon Fuel Standard Regulation (March 6, 2018), Subsection 95481 Definition and Acronyms (29). "Credit Generator" means a fuel reporting entity or a project operator that generates LCFS credit in the LCFS program.

(ARPU1_42-3)

Comment: Publicly-owned utilities ("POUs") are uniquely positioned to complement the state's transportation electrification efforts by tailoring programs to the specific needs of the communities they serve. As POUs have no shareholders or profit motivations and are directly accountable to their customers through locally elected public officials, they serve as their customers' caretakers of LCFS credits. LCFS credit revenue is a critical source for many of the POU transportation electrification incentive programs. By providing EDUs, and POUs in particular, with LCFS credits generated from electricity as a transportation fuel, CARB ensures that the customers that incur the costs to develop and maintain the electric infrastructure necessary to safely and reliably charge EVs also receive the benefits.

…

As local government agencies that share many of the same public service responsibilities as the State, POUs are uniquely positioned to satisfy the broader policy objective of ensuring our State's transportation electrification programs deliver equitable benefits to all Californians. The Joint POUs strongly encourage CARB to reject proposals that do not provide the same level of equity to the diverse community of current and prospective EV customers. (JPOUS1_59-5)

Comment: The discussion during the CARB Board meeting, calling for LCFS residential EV credits to fund a statewide POS rebate program for the purchase/lease of new EVs, concerns NCPA and SCPPA. Revenue generated by the sale of residential EV credits is essential to funding NCPA and SCPPA member EV customer incentive programs; shifting this revenue to fund a statewide POS rebate program would adversely impact NCPA and SCPPA member programs and could result in the termination of these local programs if the POS program isn't well-designed.

Realizing our shared 2030 GHG and ZEV goals will be no small feat and requires a balanced, coordinated effort between state entities, local governments, and the private sector on three fronts: (1) customer education and outreach on ZEV options, (2) financial incentives for the purchase/lease of new and used ZEVs (at least for the next few years), and (3) fueling/charging infrastructure to support the broad adoption of ZEVs. Woven throughout all of these efforts is the principle of equity—ensuring that *all*

customers can access and utilize clean transportation alternatives, including those in disadvantaged communities who may not be able to afford new ZEVs.

NCPA and SCPPA welcome closer coordination with CARB on how our members' programs best complement CARB's own programs to deliver meaningful benefits within our member communities and in support of the State's climate change and clean energy policy objectives. (NCPASCPPA1_142-2)

Comment: Publicly-owned utilities, such as the Los Angeles Department of Water and Power are in an optimal position to utilize LCFS credit proceeds to facilitate the deployment of charging infrastructure, which is lacking in our city and in our state, and is an impediment to the rapid adoption of electric vehicles that we seek.

At LADWP, we provide generous charging station rebates and install publicly accessible charging stations, including in disadvantaged communities. And this program significantly helps to reduce financial impacts on our customers, and allows us to invest in programs that benefit everyone. (UTILITIES1_T47-6)

> **Agency Response:** The commenters' express that the Publicly-owned Utilities (POU) are uniquely positioned to support electrification of transportation and several POUs have developed customized programs for promoting electric transportation in their territories. Thus, the proposed statewide rebate program must be designed without undermining POUs ability to continue their programs.
>
> Staff believes all the utilities opting into the program would like the flexibility to participate in the statewide rebate and still be able to retain some value to offer other utility-specific transportation electrification programs. Therefore, staff proposed that opt-in utilities must contribute a minimum percentage of base credits, or the base credit proceed, for the statewide rebate program while the remaining share can be used for funding other programs that promote the use of electricity as a low carbon transportation fuel.
>
> In 2017, IOUs accounted for over 80 percent of base credits issued for residential EV charging. Whereas, large POUs accounted for 14 percent and the medium and small POUs only 4 percent. Thus, contributions from IOUs would be most critical to ensure a healthy funding at the outset of the statewide rebate program. Further, the IOUs are already using the majority of the value they raise from LCFS credit sales for providing rebates to consumers, whereas, the POUs have chosen to focus some value towards other programs as well, for example, deployment of charging infrastructure. The smaller POUs rely more on the LCFS value to support their transportation electrification programs that are designed to overcome specific challenges in their service areas.
>
> Therefore, staff proposed, at the outset of the program, the IOUs must contribute at least 67 percent of their base credits or resulting proceeds for the statewide rebate, the large POUs contribute at least 35 percent and medium POUs contribute 20 percent. Given small POUs receive only a tiny fraction of total base

credits, staff proposed they may choose not to contribute any credits at the beginning of the statewide rebate effort. Starting 2023 and in the subsequent years, the contribution from the large, medium, and small POUs would increase to 45 percent, 25 percent, and 2 percent, respectively.

E. Regulated Entities

E-1. *Support for Proposed Regulated Entities Amendments*

E-1.1. Multiple Comments: *Support for the Proposed Military Applications Provisions*

Comment: Likewise, WSPA supports the exemption of any deficit-generating fuel for military end use while removing military applications from end use exempt status. (WSPA2_61-6)

Comment: Neste supports the inclusion of fuel used in military tactical vehicles and support equipment on an opt-in basis. Disallowing fuels from generating credits because solely because of end-use application has unnecessarily increased logistic costs and has overly complicated supply decisions. Allowing otherwise credit-generating, low-carbon fuel to generate credits supports the expansion of low-carbon transportation fuels in California and the growing diversity of the State's fuel supply; and allows military uses to be included in the growing demand for low-carbon fuels. (NESTE1_76-8)

Comment: REG strongly supports…removing the exemptions for military tactical vehicles and aircraft. (REG1_88-6)

Comment: CalETC supports the draft regulation order's proposal to allow military bases to earn LCFS credits including electricity LCFS credits.

…

20. *CalETC supports the draft regulation order's proposal to allow military bases to earn LCFS credits, including electricity LCFS credits.*

CalETC agrees with the draft regulation order allowing military bases to generate LCFS credits for vehicles and non-road equipment if they choose to do so. Military bases are either the charging station owner or user and are important early adopters of EVs. (CALETC1_96-23)

> **Agency Response:** Staff appreciates the commenters' support for the exemption of deficit-generating fuel for military applications, while allowing alternative fuels used in military tactical vehicles and aircraft to opt-in to receive credit in the program.

E-1.2. Multiple Comments: *Support for the Proposed Amendments to the Regulated Entities Classification*

Comment: LADWP supports the updates related to classifying entities subject to the LCFS regulation in this section to improve clarity. The subdivision of the classification of Regulated Entity is helpful in making the distinction between each role an entity may

fall under. It was also helpful that ARB notes that an entity may be subject to more than one classification. (LADWP1_38-3)

Comment: 15. CalETC supports the draft regulation order's proposal for EDUs to be "opt-in fuel reporting entities" rather than "regulated entities" as they are in the current LCFS.
…

15. CalETC supports the draft regulation order's proposal for EDUs to be "opt-in fuel reporting entities" rather than "regulated entities" as they are in the current LCFS.

CalETC appreciates the more accurate characterization of opt-in entities in the draft regulation and the clearer rules for opting in or opting out. This change will encourage more parties to become voluntary LCFS credit generators and make the program more effective. (CALETC1_96-18)

> **Agency Response:** Staff appreciates the commenters' support for the proposed amendments to clarify the regulated entities classification in LCFS.

E-1.3. *Support for the Proposed Amendments in Section 95483*

Comment: 1. <u>Include Producers of Biomass Power as Fuel Reporting Entities Under Section 95483.</u>

Under current law, only EDUs qualify for the credit, and the credit is based on an average carbon intensity (CI) index that does not reflect the value of specific producers. Current law allows RNG producers to have the value of their gas based on a specific, and favorable, CI that is not simply the average of the CI of the natural gas system. Proposed changes to Section 95483 allow our members to become "fuel reporting entities" much like RNG producers, and benefit from the LCFS by being recognized for the environmental value of their fuel. In addition, these changes make California law consistent with the RFS, where producers, and not utilities, are the generators of RINs. For these reasons, we SUPPORT changes to Section 95483. (CBEA1_128-3)

> **Agency Response:** Staff appreciates the commenter's support for the proposed amendments in section 95483. The utilities will remain the credit generator for base credits for non-metered residential EV charging. However, staff is clarifying that other entities are also eligible to claim credit for metered EV charging and have different options to use a certified CI.

E-1.4. *Support for the Proposed Amendments to Clarify the Credit Generator Role for Electricity Used as a Transportation Fuel*

Comment: LADWP supports ARB's efforts to clarify the specification for each classification of electricity used as a transportation fuel. Specific comments for each classification are as follows:

- Residential EV Charging – LADWP supports the differentiation between “Base Credits” and “Incremental Credits.” LADWP supports the proposal that an EDU is the credit generator for base credits because EDU's are responsible for the generation, transmission, and maintenance cost of the electricity used. LADWP supports the addition of incremental credits for any entity to generate, …
- Non-Residential EV Charging – LADWP supports simplifying previous classifications (Fleet, Public Access, Private Access) into one classification under Non-Residential. (LADWP1_38-5)

  Agency Response: Staff appreciates the commenter’s support for the proposed amendments to clarify the credit generator role for electricity used as transportation fuel.

E-2. *Fuel Reporting Entities for Hydrogen*

Comment: Under section 95483. Fuel Reporting Entities (b) (1) (E) Hydrogen

Hydrogen producers should be provided the opportunity to report and claim credits where the hydrogen production is dedicated to supply H2 to transportation fueling stations. This case especially applies to renewable hydrogen production where the responsibility and pathway starts with the dedicated renewable H2 producer. (FCE1_50-1)

Agency Response: In the interest of ensuring that all quantities of hydrogen dispensed for transportation use are reported to the program, staff has designated the fueling supply equipment owner as the first entity responsible for reporting (and thereby generating credits). However, in the interest of flexibility and to avoid risk of double reporting, the regulation allows the first entity to contractually designate another party (including the fuel producer) as the fuel reporting entity. Through these contractual agreements, the value of LCFS credits can also be distributed across the supply chain.

E-3. *Energy Density of Renewable Propane and Naphtha*

Comment: We also request clarification that renewable propane will use propane’s energy density on Table 4 and request that CARB add renewable naphtha to Table 4 as well. CARB may already have data on these products from different RHD producers in their pathway applications. If not, REG is willing to assist in the calculation of these energy densities using real world data. (REG1_88-14)

Agency Response: Both renewable propane and fossil-based propane will use the energy density given in Table 4 for reporting megajoules (MJ) of fuel. Table 4 contains energy density or conversion factors only for those fuels that can be reported for credit or deficit generation. Renewable naphtha can be recognized as an energy input or an energy co-product in a pathway, however, to date there is no pathway for naphtha used directly for transportation use so it is not proposed to be included in Table 4. The energy density of naphtha is

provided in the CA-GREET model (Fuel_Specs tab) for use in determining the CI of fuels that utilize naphtha as a blendstock (such as renewable gasoline) or are co-produced with naphtha.

E-4. *Specified Source Feedstocks*

E-4.1. Comment: We further recommend that section § 95488.B(g) clarify that the emissions at the point of origin of a waste or residue are zero, in consideration of the fact that the material would still be produced in the absence of the project. This would be aligned with the treatment of wastes and residues under the LCA methodology for biofuels specified by the European Renewable Energy Directive, which specifies that wastes and residues "shall be considered to have zero life-cycle greenhouse gas emissions up to the process of collection of those materials" for the project.[1]

[1] DIRECTIVE 2009/28/EC

…

We also look forward to continuing to explore opportunities to develop low carbon waste-to-fuels projects in the State, bringing further investment and high-quality jobs to California's clean fuels industry. (ENERKEM1_135-3)

> **Agency Response:** It would be inappropriate to specify that all wastes or residues have zero emissions at the point of origin. While this is true for some waste streams (e.g., used cooking oil), under the LCFS CI determination methodology non-zero emissions are attributed to some wastes or residues (e.g., crop residues which would have been left in place in absence of the project but instead are harvested and transported to the fuel production facility), including negative (avoided) emissions do to the waste treatment processes that would take place in the absence of the project (e.g., avoided methane emissions from dairy manure treated in open lagoons).

E-4.2. Comment: Page III-94: The Staff Report designates waste-derived fuels and pipeline-injected biomethane from landfills as "specified source feedstocks" to help provide transparency of the feedstock chain for high-risk feedstocks which would be subject to additional documentation requirements. The Task Force requests that CARB ensure that the additional documentation requirements are not overly burdensome compared to documentation requirements for other feedstocks to the point of discouraging the production of waste-derived fuels and pipeline-injected biomethane from landfills. (TASKFORCE1_89-5)

> **Agency Response:** The proposed requirements for biomethane as a specified source feedstock are in line with current LCFS practice in which 1) an entity reporting biomethane must identify the landfill or other source from which the fuel was procured, and 2) feedstock production facilities may contribute site-specific data in the pathway application (or must, if no standard feedstock CI is provided by CARB, as is the case for landfills and dairy manure operations, for example). The requirements enable accurate CI determination and enable CARB staff and verification bodies to verify reporting accuracy, e.g., the total quantity of

biomethane reported for credit generation does not exceed the amount produced by a given source, and there are no double claims on environmental attributes.

E-4.3. Comment: Page III-137: The Staff Report also designates separated food waste as a "specified source feedstock" subject to additional documentation requirements. The Task Force requests that CARB ensure that this additional documentation is consistent with SB 1383, implementing regulations such that it does not discourage use of separated food waste as a feedstock to produce fuel. (TASKFORCE1_89-6)

Agency response: The commenter refers to the provision requiring applicants using specified source feedstocks to maintain chain of custody evidence, including a copy of the separated food waste plan required under the RFS program, where applicable, to be provided to verifiers or to the Executive Officer upon request. Staff did not accept the commenter's request because the SB 1383 implementing regulations are not yet adopted and, therefore, cannot be relied upon in this rulemaking. Chain-of-custody documentation is necessary for specified source feedstocks to ensure that the source, type and quantity of the feedstock is verifiable and that the correct CIs are assigned to the fuel pathway application. Staff considers this evidence to be indispensable in establishing that a material is indeed a waste and, therefore, warrants the low CI values that incent use of food waste as a feedstock.

E-5. *Clarification for Proposed Amendments to Regulated Entities Classification*

E-5.1. Comment: In particular, we wish to comment on the following: … (2) clarification that a "fuel reporting entity" would be a "regulated entity" and that, accordingly, fuel reporting entities can trade LCFS credits under the proposed amendments.

…

2. Fuel Reporting Entities' Ability to Trade LCFS Credits

Under the proposed amendments, a "fuel reporting entity" is any entity who acquires reporting entity status for any fuel even if that fuel is sold to another party with such status and the seller does not retain the ability to generate credits or deficits.[6] Also, under the proposed amendments, a regulated entity may buy and sell LCFS credits.[7] A "regulated entity" is defined as "an entity subject to any requirement pursuant to this subarticle," which implies that the definition covers fuel reporting entities as such entities are subject to the requirements of the LCFS.[8] Therefore, it follows that fuel reporting entities are entitled to trade LCFS credits even if they do not retain credit or deficit generator status for fuel that they buy and sell and do not retain reporting entity status. We request that CARB clarify this point in the amended LCFS regulations as it is important for a functioning and liquid market for parties participating in the LCFS Program to clearly understand their ability to trade LCFS credits.

[6] See Section 95481(a)(59) of the Proposed Amendments.

[7] See Section 95487(a)(1)(B) of the Proposed Amendments.

[8] See Section 95481(a)(110) of the Proposed Amendments.

(ES1_97-2)

Agency Response: Staff clarifies that fuel reporting entities are allowed to transfer LCFS credits in the LRT-CBTS even if they pass on the credit or deficit generator status for the fuel.

E-6. *Designee as an Opt-In Entity*

Comment: As defined in Section 95483.1(a)(1)(A), an entity who provides a fuel as specified in Section 95482(b) and meets the requirements of Section 95483 can opt into the LCFS program in the capacity of a Fuel Reporting Entity (FRE). In review of these sections, electricity as a fuel would qualify and Non-Residential EV Charging equipment would also qualify if the entity meets the Fuel Supply Equipment (FSE) registration requirements outlined in Section 95486.2(b)(8), reporting requirements in Section 95491, and recordkeeping and auditing requirements outlined in Sections 95491.1, and no other entity is generating credits for the same Fuel Supply Equipment. Upon further review of FSE registration requirements under Section 95843.2(b)(8)(B), it appears that entities that do not own the equipment, but are registering on behalf of the owner, are eligible to act in an agency capacity on behalf of the owner. SRECTrade supports this structure to register FSE. We believe this is like the role SRECTrade plays in its existing markets as an agent aggregator. Allowing agent aggregators will enable participation from more eligible entities, regardless of resources and total financial value to the party owning the FSE. It is likely that eligible entities owning FSE may not necessarily have the capability, experience or sophistication necessary to participate in the CA LCFS market. Given the importance of this role in assisting the registration of entities and the FSE they own, we believe it would be valuable to define Agent Aggregators or Third-Party Managers as an Opt-In Fuel Reporting Entity under Section 95483.1, similarly to how Project Operators or Clearing Service Providers are defined. We believe this would provide transparency in the role companies like SRECTrade would be looking to provide in the CA LCFS program. This role could effectively be a subcategory of Fuel Reporting Entities that would help clarify that the entity is reporting on behalf of a variety of different underlying FSE owners. The distinguishing identifier for each piece of FSE would be the unique LCFS FSE ID. This would allow the Agent Aggregator to register the FSE of many different entity owners under a single account and would help facilitate management of these assets in LRT-CBTS. In lieu of an account registration form for LRT-CBTS for each entity owning FSE, SRECTrade would recommend CARB develop a document like the SCHEDULE A Generator Owner's Consent used by PJM Environmental Information Services for registration in the PJM GATS REC registry (see Exhibit A attached). (SREC1_111-1)

Agency Response: Staff realizes that a third-party aggregator or a designee of credit generator could be critical to promote participation from smaller entities – specially providing smaller quantities of credit generating fuels like natural gas, propane, hydrogen, or electricity – who may not be able to participate directly in the program due to administrative needs. Therefore, staff proposed to include

the flexibility for credit generator for non-liquid fuels that are unable to participate directly in the program to contractually designate a third-party on its behalf to be the credit generator in the program. This flexibility would allow a third-party aggregator to participate in the program on behalf of other entities assuming the role of fueling reporting entity and credit generator on behalf of the designating entity. Hence, staff does not believe creating a new opt-in entity role is necessary.

F. Average Carbon Intensity Requirements and Fuel Availability

F-1. *Support for the Proposed Average Carbon Intensity Requirements*

F-1.1. Multiple Comments: *Support for the Proposed 2030 Target*

Comment: We support the increased stringency from an 18% reduction target by 2030 in the Scoping Plan to 20% by 2030 in the ISOR. This stronger target is justified by independent analyses including a recent study that CALSTART contributed to with Cerulogy.[2]

[2] Malins, Chris (March 2018). California's Clean Future: Assessing Achievable Fuel Carbon Intensity Reductions Through 2030. Cerulogy. https://nextgenamerica.org/wp-content/uploads/2018/03/Cerulogy_Californias-clean-fuel_March2018-1.pdf

(CALSTART1_B6-1)

Comment: Just wanted to make two other reflections -- or two specific reflections. We support the 20 percent reduction target. We wouldn't of opposed if it were higher. We realize that there's a number of subsectors within the transportation system that could do a lot better than what the estimates or assumptions expect.

Particularly me and the heavy duty have -- we've taken off this last year. We now count 180 zero-emission buses on the road in California, and could see thousands by the end of year 2020; something that I think would have surprised people even looking at this closely a year ago. We also now have -- Kenworth has their low NOx 12-liter engine for sale. There's an HVIP incentive, you can get it today. And we see those trucks expanding as well, predominantly filled with renewable fuel.

So I think there's a -- there's a huge growth in that market that's going to increase the chances of being able to achieve a higher CI target. But we do appreciate staff being very adult about not wanting to get too far ahead of ourselves, and we support the proposal as is. (CALSTART2_T13-2)

Comment: We support the board in adopting staffs proposal to extend the policy to 2030 and double the emissions reduction target from a 10 percent reduction in average fuel carbon intensity in 2020 to a 20 percent reduction in 2030. This will send a clear message to the market for low carbon fuels that demand will grow steadily over the long term.

By setting steadily growing long term goals, the LCFS supports innovation and progress across the transportation fuel sector. By adopting these amendments, extending the LCFS to 2030 and doubling the emissions reduction targets, the California Air Resources Board will be speeding California on its way to a clean transportation future. (GROUP1_B17-1)

Comment: First, we'd like to support staff's proposal to require a 20 percent carbon intensity reduction by 2030. (CHARGEPOINT2_T8-2)

Comment: The Coalition for Clean Air supports amending LCFS to increase reduction targets by 2030 to ramp up California's goal to reduce greenhouse gas emissions and air quality improvement. (CCA2_T12-1)

Comment: Ambitiously strengthening the LCFS through 2030 also helps advance a key AB 32/SB 32 priority - leveraging the state's climate leadership to drive greenhouse gas emission reductions in other jurisdictions. As a global climate policy leader with a well-developed policy structure, California is uniquely positioned to provide support and resources to other jurisdictions that are developing climate policy frameworks. California's LCFS is a model policy, variations of which have been replicated or are under consideration in several other subnational and national jurisdictions. BICEP supports ARB's work to develop a policy framework that is exportable. Building a regional, national, and international market for low carbon fuels is vitally important to send the right market signals to industry to invest in projects with scale. (BICEP1_11-3)

Comment: We are inclined to accede to CARB's judgement and support the changes recommended regarding program compliance benchmarks. That said, obligated parties have been aware of the 2020 reduction requirements for more than 10 years and it seems to us that if they are not on a smooth glidepath toward compliance that this circumstance conveys far more about their level of enthusiasm for program compliance than the progress and availability of clean fuels technology.

Though we support the current proposal, we would strongly oppose any further amendments. Government certainty, which our industry has rarely enjoyed, is paramount for the clean fuels sector as is an increasingly stringent requirement that portends future growth. We believe that a 7.5% reduction in carbon intensity in 2020 is readily achievable and that annual increases of 1.25% from that point forward represent the minimum advances needed to continue drawing investment into the sector. (NBBCABA1_29-6)

Comment: LADWP supports ARB's effort to reduce the carbon intensity (CI) of transportation fuel by at least 7.5% by 2020, and 20% by 2030, as amended in the Proposal. (LADWP1_38-2)

Comment: Stable Program Necessary to Support Capital Investments

Neste, along with many other low-carbon fuel producers, have made significant capital investments in response to the LCFS implementing a demand for renewable or low-carbon transportation fuels. Neste supports CARB's efforts to set an increasing standard beyond 2020. Having an increasing standard will continue to provide forward-looking drivers to incentivize production of low-carbon fuels and additional investment in new, lower-carbon feedstocks, investments in new production capacity, and commercial drivers to attract low-carbon fuels to the California market.

Specifically, Neste supports a target of 20%[7] reductions by 2030 and smoothing the compliance trajectory. This level is attainable and will require continued efficiency increases in staff's ability to complete pathway applications - especially for new and novel feedstocks and production processes - in a timely manner that adequate recognizes the carbon reduction impacts. (NESTE1_76-2)

Comment: 5. 2030 Target: approve staff's proposal to increase the statewide Carbon Intensity (CI) reduction target to 20% by 2030.

…

V. Approve staff's proposal to increase the statewide CI reduction target to 20% by 2030.

Tesla supports staff's proposed CI reduction target of 20% by 2030 in this rulemaking. Tesla agrees that increasing the stringency of the LCFS carbon intensity target is necessary to achieve California's 2030 GHG emissions reduction goal, and maintaining steady carbon intensity reductions through 2030 is essential to ensure the ongoing success of the program. Given the anticipated electrification of the heavy-duty sector and significant growth in EV adoption across the state, the state should easily exceed the proposed target of 20% by 2030. Tesla encourages staff to explore increasing the targets in future rulemakings if the market becomes oversupplied with credits, as this will ensure that the program continues to drive progress toward cleaner fuels.

Based on the foregoing, we believe CARB should…v) increase the 2030 CI reduction target to 20% to ensure the state continues to reduce the carbon intensity of its transportation fuels. (TESLA1_79-6)

Comment: On behalf of Tesla, I just want to express our support for staff's proposed 2030 target. (TESLA_T26-1)

Comment: 1. We support staff's proposal to increase the requirement to a 20 percent carbon-intensity reduction by 2030. New analysis points to an even higher target being possible.

NRDC supports staff's proposal to reduce the CI of both gasoline and diesel fuels 20 percent by 2030. A consultant report by Cerulogy (2018) "California's Clean Fuel Future: Assessing Achievable Fuel Carbon Intensity Reductions Through 2030," confirms that staff's feasibility assessment is not only reasonable, but is conservative.[3] We recommend that ARB consider future upward adjustments to the standard if more rapid progress is made based on compliance data. At the same time, we also ask ARB to continue to monitor the progress of similar clean fuel standards in other major

[7] *Staff Note:* Communication with the stakeholder clarifies that the figure of 30 percent in the original comment letter is the result of a typo, and that the stakeholder intended to support a target of 20 percent. The email exchange is included in the rulemaking file.

jurisdictions, such as Canada, to update its supply assessment of low-carbon fuel supplies for California.

[3] https://www.arb.ca.gov/lispub/comm/bccomdisp.php?listname=lcfs18&comment_num=5&virt_num=5

…

Establishing strong signals now for the post-2020 timeframe is consistent with the transformational policies outlined by ARB under its First Update to the AB 32 Scoping Plan. California's near-term efforts to establish a strong market for clean, low carbon fuels are critical to make sure the state is on the pathway to the deeper reductions needed to meet the 2050 goals. (NRDC1_81-2)

Comment: But we know the LCFS train can go even further, and we encourage the Board to support the 20 percent carbon intensity target that staff has proposed. (NRDC2_T19-1)

Comment: Support of Change in Annual Carbon Intensity Requirements for Gasoline and Diesel

AMP supports ARB's decision, outlined in section 95484, to target a 20 percent reduction in transportation fuel carbon intensity by 2030. AMP actively invests time, resources, and capital towards lowering GHG emissions and advancing technologies to decarbonize both California and the United States. Accordingly, AMP applauds ARB's efforts with their intent to not only advance these climate goals, but also to support LCFS credit prices which are instrumental to the continued development of biomethane projects both inside and outside of California. (AMP1_86-2)

Comment: Clean Energy supports the proposed amendment to increase the stringency of carbon intensity (CI) targets in order to achieve California's 2030 GHG reduction goals as established in SB 32. Increasing the 2030 Cl reduction target to 20% and normalizing the annual reductions from 2020-2030 is a sensible approach for promoting the increased use of a diversified mix of low carbon fuels in state while maintaining credit market stability and transparency. Clean Energy cautions Staff from considering any further increases to the 2030 Cl target beyond 20% at this time as this proposed target relies on various assumptions for growth in transportation fuel demand and electrification that remain unproven at this time. Market stability is key for increasing low carbon fuel project development but if the program falls short of an aggressive 2030 Cl target, the LCFS program becomes subject to uncertainty which is detrimental to low carbon fuel growth. Clean Energy recommends any increase of the 2030 target should be reviewed at a later date when more data on the actual supply of low carbon fuels becomes available. (CE1_92-2)

Comment: 6. CalETC supports the draft regulation order's proposal to increase the stringency of the LCFS in the next decade, with a ramp that goes from a 7.5% carbon-intensity reduction for gasoline and diesel in 2020 to a 20% reduction in 2030 with biennial reviews.

6. CalETC supports the draft regulation order's proposal to increase the stringency of the LCFS in the next decade, with a ramp that goes from a 7.5% carbon-intensity reduction for gasoline and diesel in 2020 to a 20% reduction in 2030 with biennial reviews.

The draft regulation order proposes to increase the LCFS overall requirement from a 7.5 percent carbon-intensity reduction requirement in 2020 to a 20 percent carbon-intensity reduction requirement in 2030. CalETC supports this proposal. Our recommendation is supported by modeling conducted by ICF International in a 2017 report called "Post-2020 Carbon Constraints: Modeling LCFS and Cap-and-Trade."[7] Other modeling by independent experts shows that proposal in the draft regulation order is possible.[8] In addition, CalETC agrees with staff's goal to keep credit prices in a reasonable range as stable prices make a huge difference in EDU programs funded by LCFS credit proceeds.[9]

[7] Available at: http://www.caletc.com/wp-content/uploads/2016/08/Final-Report-Cap-and-Trade-LCFS.pdf
[8] Available at: https://nextgenamerica.org/wp-content/uploads/2018/03/Cerulogy_Californias-clean-fuel-future_March2018-1.pdf
[9] See CARB staff's Initial Statement of Reasons for this rulemaking pages EX-9 to EX-10.

Because the LCFS may result in additional unanticipated innovation in the transportation fuel and vehicle technology sectors, CalETC recommends the regular review process include an assessment regarding the 2030 reduction requirement. If this reduction requirement is deemed too low or too high, staff would recommend appropriate amendments for the CARB Board consideration, with direction to adjust the requirement in support of a robust requirement that best supports the state's climate change goals. (CALETC1_96-8)

Comment: 6. The increased carbon intensity target for 2030 is feasible and will provide many benefits.

…

6. The increased carbon intensity target for 2030 is feasible and will provide many benefits.

BAC supports increasing the 2030 target to a 20 percent reduction in carbon intensity. Recent studies by Cerulogy and others have shown that that is a feasible target and will help the state to achieve its 2030 climate goals.[5]

[5] https://nextgenamerica.org/wp-content/uploads/2018/03/Cerulogy_Californias-clean-fuelfuture_March2018-1.pdf

(BAC1_99-8)

Comment: The LCFC therefore regards the extension of California's program to 2030, and the reduction of CI to 20% as major victories and commends ARB staff, management and the Governing Board on these accomplishments. To the low carbon fuels industry, policy stability and integrity are essential to success. By setting a CI table out to 2030 that aggressively decarbonizes California's transportation fuel, California is sending a strong and clear market demand signal that will correspondingly

increase low carbon fuel supply and the development of related businesses, infrastructure, and technologies. (LCFC1_105-2)

Comment: First, we support the proposed doubling of the overall program target and extension through 2030. (RNGC2_T43-1)

Comment: We do just want to say up front very much support the staff's recommendation for a 20 percent carbon reduction out to 2030. (UTILITIES1_T47-2)

Comment: AECA generally supports the proposed extension of the LCFS program and believes that a 20 percent target by 2030 is appropriate. (AECA1_72-2)

Comment: I'm going to talk a little bit about the nexus between LCFS and the importance of this as we work to achieve dairy methane reductions. It's critical to CARB's SLCP strategy, and the desired reduction in dairy methane, which is why we support the extension of the LCFS and believe a 20 percent target by 2030 is appropriate. (ACEA2_T44-1)

Comment: First, we support CARB's proposed 20 percent target for 2030…

…

And then finally, today I submitted a petition for more than 1,700 UCS supporters across California in support of … increasing the program's intensity target to 20 percent. (UCS2_T53-2)

> **Agency Response:** Staff appreciates the support for the proposed changes to the 2030 CI target.
>
> Several comments recommend that CARB monitors the progress of the LCFS credit market and change the targets in the future in the case of the credit market becomes over- or under-supplied in the future. As is current practice for all ARB programs, staff will maintain a close watch on the conditions of the LCFS credit market to insure that it is functioning correctly and to propose any potential adjustments as necessary. CARB provides regular updates on the LCFS credit prices and transactions, quantities and the carbon intensity performance of transportation fuels used in California, and other useful information about low carbon fuels on the LCFS's Data Dashboard website which can be found here: https://www.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm

F-1.2. Multiple Comments: *Support for the Proposed 2020 Target*

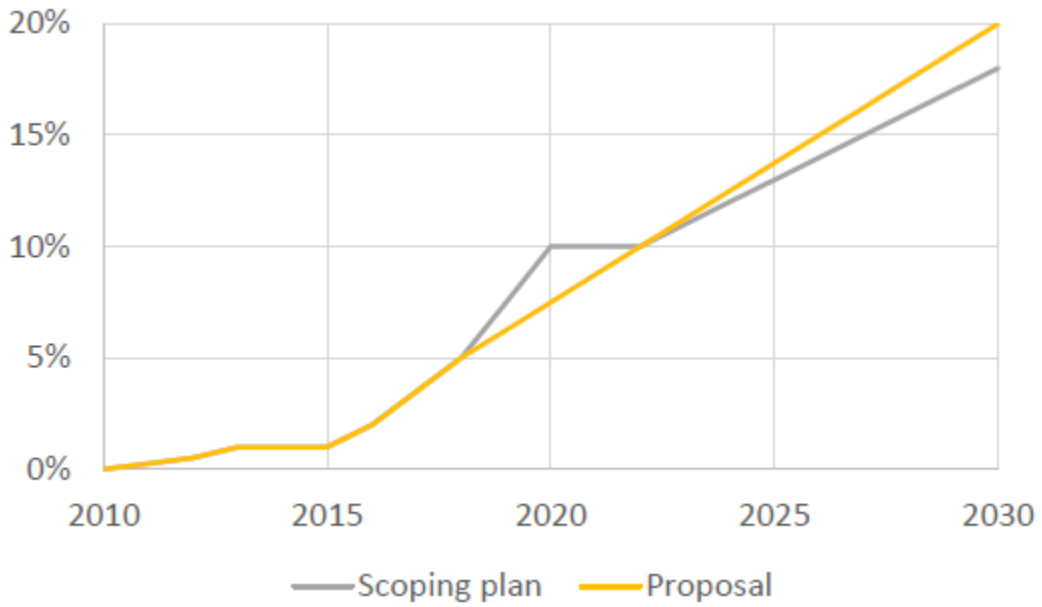
Comment: Lastly, we support modifying the 2019 and 2020 CI targets; though even at these targets, the program is not sustainable in the near term. (ANDEAVOR2_T10-4)

Comment: In general, BICEP supports ARB staff's proposal outlined in the ISOR that adjust pre-2020 targets. A near-term benchmark schedule with a linearly and consistently strengthened CI target will ensure that the program continues to provide a

dependable and increasingly strong market signal to the low carbon fuel economy. (BICEP1_11-1a)

Comment: The proposed compliance schedule improves over the scoping plan proposal

The proposed compliance schedule, with a steady increase of 1.25 percent stringency each year between 2019 and 2030, is an important improvement over the schedule described in California's 2017 Climate Change Scoping Plan. The schedule proposed in the scoping plan reached 10 percent by 2020 but then plateaued for a few years before resuming 1 percent per year growth to an 18 percent target in 2030. The revised schedule reaches a higher 2030 target of 20 percent, and with predictable increases in the annual target sends a clearer message to fuel markets that demand for clean fuels will grow steadily over time.



The comparison of the two compliance schedules in Appendix E Section F 2 of the ISOR illustrates that the schedule proposed in the scoping plan was expected to lead to large fluctuations in the banked credits balance (see Figure F10) and estimated credit prices (Table F10), with credit prices at the cost containment limit for three years, followed by a precipitous drop of 50 percent in three years. Estimates of credit prices for the 2018 amendments proposal stay within 10 percent of a value of $125 throughout the whole compliance schedule. While higher credit prices theoretically support higher levels of investment, it is important to remember the extended timeframes required to move from an investment decision to delivery of fuel. While it is not surprising that some low carbon fuel producers would prefer more aggressive near-term targets and associated higher credit prices, a stable long-term credit price that avoids credit price spikes that trigger the cost containment mechanism and subsequent credit price drops is more likely to foster stable long-term investment over the whole duration of the LCFS program. (UCS1_53-3)

Comment: The LCFS program poses many challenges, Andeavor supports CARB's decision to modify the 2019 and 2020 Carbon Intensity (CI) targets. We agree this change will help to address some near term challenges the LCFS program presents given the current lack of adequate credit generating fuel supply or infrastructure to meet the goals set forth in the last rulemaking… We do not believe that the near-term targets (through 2020) proposed are a sustainable base given the current supply of credit generating fuels. (ANDEAVOR1_67-2)

Comment: RFA agrees with CARB's recommendation to slightly ease short-term CI benchmarks. While the revised short-term benchmarks remain quite stringent, they will give the marketplace more "breathing room" and flexibility, ultimately enhancing the sustainability of the program. We also support the use of a straight-line CI reduction trajectory rather than a back-loaded curve. Using a straight-line approach results in more predictable and stable market conditions for both low carbon fuel producers and regulated parties. (RFA1_80-3)

Comment: CalETC supports the draft regulation order's proposal to increase the stringency of the LCFS in the next decade, with a ramp that goes from a 7.5% carbon-intensity reduction for gasoline and diesel in 2020 to a 20% reduction in 2030 with biennial reviews. (CALETC1_96-8)

Comment: The drawing of the curve has received substantial attention, and we would like to provide our organization's perspective on it. We appreciate and respect staff's diligent work in analyzing the anticipated supply of low carbon fuels, and the corresponding anticipated availability of credits. We recognize that the steep drops in CI between 2018-2020 were not attributable to ARB policy design but instead to legal challenges. We share the concern that a prolonged period of deficits in the LCFS market would heighten political pressure against the program, and could be used as a political talking point to weaken the program in the 2020's. Within this context, we are supportive of the CI reduction curve as proposed between 2018 and 2030.

We would like to emphasize that it is only these extraordinary conditions that underlie our support for the short-term modification in the CI curve over the next several years. Program stability is of enormous importance to the low carbon fuel industry, and it is undermined by tinkering with the fundamental metric of the LCFS: the mandatory CI score that must be achieved by regulated parties for a specific year. We urge ARB to regard the CI tables to 2030 as not etched in stone but as subject to change only in extraordinary conditions where program integrity would be substantially undermined if adjustment did not occur. From a low carbon fuel perspective, weakening the CI requirements will inevitably cause some damage to the market. Therefore, ARB should resort to this measure in the future only in extraordinary circumstances and when there is high confidence that the long-term benefit will outweigh the inevitable damage. (LCFC1_105-3)

Comment: 1. Apprehension Over Aggressive Post 2020 Compliance Curve

ARB proposes to smooth the compliance curve by adjusting the existing rate of decline in annual benchmarks between 2018 and 2020, and by applying a consistent annual decline of 1.25% from 2018 to 2030, to achieve a 20% reduction in the carbon intensity of fuels by 2030. Kern appreciates ARB's responsiveness to previous comments that compliance curves should be appropriately managed to prevent imposition of a sudden dramatic reduction that would negatively affect the market and regulated parties' ability to comply. Kern supports requiring reductions in a ratable and smooth manner. (KERN1_115-1)

Comment: Therefore, while we concur with CARB's proposed changes to the near-term targets, we encourage CARB to reevaluate the 2030 target and the interim benchmarks.

…

…We agree with CARB's near-term adjustment, as our analysis indicates that making this change would delay the depletion of the credit bank to the late 2020s. (PGE1_120-4)

Comment: We also support staff's adjustment to enable the ramp to increase ever year in a linear-fashion over time between the entire 2018 to 2030 period, as opposed to an earlier proposal that would have kept the standards flat between 2020-2022 at a 10% level. Doing so will provide low-carbon fuel providers a consistent signal over time while also allowing a smooth ramp up over the entire period. (NRDC1_81-3)

Comment: CalETC supports the draft regulation order's proposal to increase the stringency of the LCFS in the next decade, with a ramp that goes from a 7.5% carbon-intensity reduction for gasoline and diesel in 2020 to a 20% reduction in 2030 with biennial reviews.

The draft regulation order proposes to increase the LCFS overall requirement from a 7.5 percent carbon-intensity reduction requirement in 2020 to a 20 percent carbon-intensity reduction requirement in 2030. CalETC supports this proposal. Our recommendation is supported by modeling conducted by ICF International in a 2017 report called "Post-2020 Carbon Constraints: Modeling LCFS and Cap-and-Trade."[7] Other modeling by independent experts shows that proposal in the draft regulation order is possible.[8] In addition, CalETC agrees with staff's goal to keep credit prices in a reasonable range as stable prices make a huge difference in EDU programs funded by LCFS credit proceeds.[9]

[7] Available at: http://www.caletc.com/wp-content/uploads/2016/08/Final-Report-Cap-and-Trade-LCFS.pdf

[8] Available at: https://nextgenamerica.org/wp-content/uploads/2018/03/Cerulogy_Californias-clean-fuel-future_March2018-1.pdf

[9] See CARB staff's Initial Statement of Reasons for this rulemaking pages EX-9 to EX-10.

Because the LCFS may result in additional unanticipated innovation in the transportation fuel and vehicle technology sectors, CalETC recommends the regular review process include an assessment regarding the 2030 reduction requirement. If this reduction requirement is deemed too low or too high, staff would recommend appropriate amendments for the CARB Board consideration, with direction to adjust the requirement in support of a robust requirement that best supports the state's climate change goals. (CALETC1_96-8)

Comment: I would commend the staff for providing a short-term carbon intensity reduction target, because frankly, I think it really does enhance the program's stability, and it also reduces any of what we see as some undesirable market impacts. (WSPA2_T48-2)

> **Agency's Response:** Staff appreciates the support for the proposed changes to the 2020 CI target.

F-2. ***2030 Target***

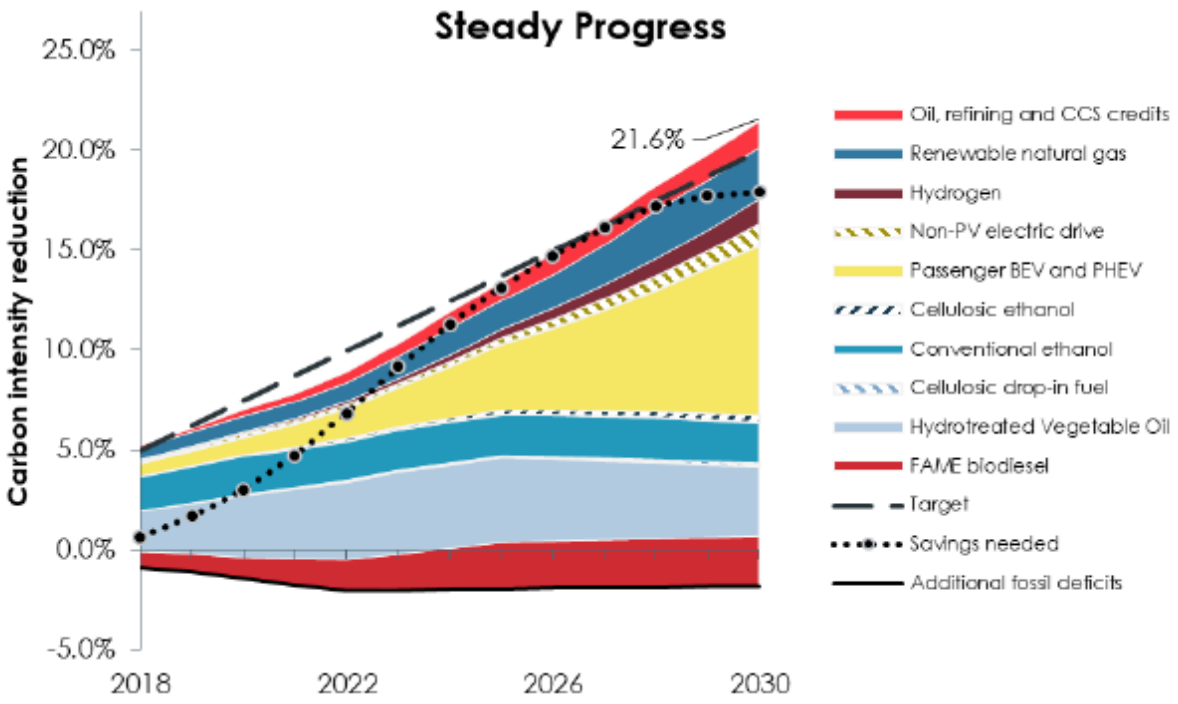
F-2.1. Multiple Comments: ***Support 2030 Target of 20 Percent, but Think it Could Be Set to Achieve Greater CI Decline***

Comment: We support CARB's proposed 20 percent target for 2030, but note that analysis shows the potential for higher targets, particularly post 2025. The board should monitor progress and raise the targets as appropriate to ensure the LCFS continues to support investment in low carbon fuels.

…

A 2030 target of 20 percent is feasible

USC strongly supports the proposed target of 20 percent by 2030. UCS, together with Ceres and NextGen, commissioned an independent analysis of low carbon fuel production by consulting firm Cerulogy. The analysis confirms that the 20 percent target is feasible under a wide range of scenarios. A chart from one core scenario below reflects that with steady progress but no major breakthroughs for the wide range of low carbon pathways, a 2030 target as high as 21.6 percent is achievable. Under the more optimistic assumptions included in the High-Performance scenario, a 2030 target of over 26 percent is achievable. The most pronounced opportunities to exceed the proposed targets come in the later years of the LCFS program, from 2025 to 2030. We encourage the board to monitor progress and raise the targets as appropriate to ensure support steady for investment in low carbon fuels throughout the program.



(UCS1_53-2)

Comment: …but we note the analysis we commissioned shows the potential for higher targets, particularly post-2025. And so we encourage this Board to monitor progress, and raise the targets as appropriate to ensure LCFS continues to support investment in low carbon fuels through the course of the coming decade. (UCS2_T53-3)

Comment: In fact, we believe the target could be stronger. According to the Cerulogy study, a 2030 target of about 26% target is attainable, and 24-25% is realistic if any one of several subsectors beats conservative expectations. One subsector, medium- and heavy-duty vehicles (MDHVs), is poised to do just that.

Already California has over 180 zero emission buses (ZEBs) deployed, and based on recent discussions with transit agencies, we foresee having 1,000 on the road by 2020—a figure that we imagine would have surprised most informed analysts even a year ago. As more ZEBs hit the roads over the next few years, they will be joined by zero emission trucks from over a dozen manufacturers in all categories.

Concurrently, Low NOx (0.02 g/bhp-hr) trucks powered by renewable fuel have begun rolling out. Earlier this year, Westport Cummins introduced its 12-liter Low NOx engine, and that engine is now available in Kenworth trucks which are eligible for incentives by HVIP today. The South Coast and San Joaquin Valley have air quality attainment goals that call for major deployments of these trucks, and as those deployments occur, we expect the LCFS to cause renewable natural gas with very low carbon intensity scores to be the predominant source of fuel for these trucks.

In sum, as outlined in the Cerulogy report, it is realistic to envision more than 200,000 medium- and heavy-duty (MHDV) vehicles on the road by 2030 that are either zero-emission or those using Low NOx technology in conjunction with predominantly renewable fuel. Such numbers support a target of at least 24%. (CALSTART1_B6-2)

Comment: I don't have a “but” slide with me as an earlier presenter did this morning. But if I did, it would say CCA would like to see a 22 percent or greater reduction by 2030 of carbon intensity created by transportation fuels.

This is achievable through the continued growth of alternatives to petroleum, such as electricity, hydrogen, renewable diesel, and renewable methane.

More ambitious LCFS will not only help California reach its clean air goals but reduce the localized air pollution, largely from fossil fuels, that damages the health of millions of Californians. (CCA2_T12-2)

Comment: And we believe ARB could even go further than that. We believe that the data shows that even a higher target is possible. And as ARB looks to future adjustments to the program, looking at the rapid progress and the credit data will be very important to looking at those higher targets. (NRDC_T19-2)

Comment: We think the State could go even further, and I think that's been expressed by a lot of other folks in the room here today. (TESLA2_T26-2)

> **Agency Response:** Staff appreciates the support for the proposed changes to the 2030 CI target.
>
> Some commenters have cited the report prepared by Cerulogy. Staff responds to the Cerulogy report in greater details in Response F-2.2 in this chapter.

F-2.2. Multiple Comments: *2030 Target should be Set to Achieve a Greater CI Decline*

Comment: A key element of LCFS policy design is its CI target and how this is tightened or otherwise adjusted over time to provide strong, steady incentives for development and expansion of low-CI fuels. Thus far, target adjustments have mainly responded to legal challenges and concerns about short-term credit shortages, but these are likely to be less prominent considerations in the future. The LCFS’s basic market-based structure with credit banking, as well as the credit clearance mechanism, pass some responsibility for managing the time trajectory of fuel development to private market actors. But ARB still has the responsibility to set and periodically adjust the CI target trajectory, as it did when the policy was adopted and has now proposed through 2030. Such a pre-announced target schedule is necessary to signal the policy’s ambition, create appropriate incentives, and provide context for market actors’ decisions to use or bank credits. With such a target trajectory in place, the credit market then both mediates the incentives for low-CI fuel development and provides information about realized and anticipated progress. Sustained high credit prices both make the incentives stronger, and signal difficulty responding in the short term.

There will always be unavoidable uncertainty on future progress in low-CI alternatives, and thus on the trajectory of future credit prices. To deal with these, ARB needs the discretion to adjust previously announced target schedules in response to large departures from projected progress. Given this uncertainty, the most basic design decision regarding targets is how to set the advance schedule relative to current projections of future progress: should the initial target schedule be biased toward greater ambition, with accompanying risk that future relaxations will be needed; or toward less ambition, with increased risk that future tightening will be needed?

This decision can be analyzed in terms of the relative cost of the two types of error. Starting too weak then tightening means missing available reduction opportunities; giving inadequate incentives, so weak initial projections may become self-fulfilling prophecies; and later imposing unanticipated lump-sum burdens on fuel distributors who have deficits. Starting too strong then loosening risks weakening the credibility of initial targets, and gives incentives to firms that expect to have deficits to resist and conceal progress in order to get targets weakened. These two concerns may have limited impact, in practice, however. Risks to credibility of targets may not be consequential because target relaxation would only occur under conditions of sustained tight credit markets, and so would impose only small losses from highly favorable positions on low-CI investors. And obstruction might not be a serious risk because the divergence of interests between firms marketing high and low-CI fuels suggests that those with the strongest interests in target relaxation would have little influence on the pace of low-CI development. On balance, the cost and disruption from setting initial target trajectories ambitiously then later making small relaxations if needed are likely to be less than those from setting initial targets too weak and later having to tighten them. For the proposed target trajectory through 2030, since several plausible scenarios have been identified to reach the proposed 20 percent reduction or more,[11] this reasoning suggests that ARB should consider an initial trajectory with somewhat stronger targets, reaching a few percent beyond 20 percent CI reduction by 2030.

[11] Initial Statement of Reasons, Chapters 5 and 8, available at https://www.arb.ca.gov/regact/2018/lcfs18/isor.pdf; See also C. Malins, "California's clean fuel future: assessing achievable fuel carbon intensity reductions by 2030," March 2018. *Available at* https://nextgenamerica.org/wpcontent/uploads/2018/03/Cerulogy Califomias-clean-fuel-future_March2018-1.pdf

(UCLA1_B8-6)

Comment: …and we're here today in support of this proposal to not only extend the LCFS, but to extend it more ambitiously to at least 20 percent – 22 percent, I mean, carbon intensity. We'd like to see the stronger number, 22 percent.

Many of our folks like Levi Strauss, Dignity Health, Salesforce have large fleets in California. We understand the ramifications. But we do believe this has significant positive benefits in California, not only emission reductions, public health, but it has since 2011 spurred a very strong industry in California. We recognize, you know, $2 billion has been invested in clean fuels promotion in California. So given the recent analyses, we believe that 22 percent is accomplishable and we'd urge that the Board adopt the higher number when they look for extending the program. (CERES1_T14-1)

Comment: Our organization supports the proposal going beyond the 18 percent in the scoping plan, and think that, as others have said, that recent research shows that we can go beyond the 20 percent in the proposal to 22 percent or higher.

We think that going beyond will just strengthen the signal to continue moving towards a cleaner air future and a stable climate. (HMO_T15-2)

Comment: As a health professional, I write to provide my strong support for CARB adopting the strongest possible Low Carbon Fuel Standard target for 2030. We believe that the LCFS is a critical program driving down the harms to our air, our climate and communities most impacted by fossil fuels.

…

2030 Target - Establish a 2030 Carbon Intensity Target of 22 Percent or More

We appreciate that the proposal takes a stronger approach to the 2030 target than the 18 percent reduction envisioned in the 2030 Scoping Plan. CARB's AB 32 Environmental Justice Advisory Committee recommended that the target be set at 30 percent.[2] Further, recent research suggests that even a 22 percent target for 2030 could be viewed as conservative.[3] We believed that the Scoping Plan was far too conservative and that the current proposal should be adjusted to achieve at least 22 percent reduction in carbon intensity by 2030.

[2] California Air Resources Board. AB 32 Environmental Justice Advisory Committee. "Recommendations for Proposed 2030 Target Scoping Plan Update." March 2017. https://www.arb.ca.gov/cc/scopingplan/2030sp_appa_ejac_final.pdf

[3] Cerulogy, March 2018. "California's Clean Fuel Future: Assessing Achievable Fuel Carbon Intensity Reductions Through 2030." https://www.ucsusa.org/pregs/2018/scientists-say-california-can-get-tougher-clean-fuels#.WsacBy7waUk

…

In closing, I support the vision offered in the proposal to exceed the target considered in the 2030 Scoping Plan, but encourage the board to pursue a stronger target for 2030. (VB1_10-1)

Comment: Attached please find letter from 27 health and medical organizations and dozens of health professionals in support of the strongest possible LCFS target.

…

On behalf of the undersigned health and medical organizations and health professionals, we write to provide our strong support for CARB adopting the strongest possible Low Carbon Fuel Standard target for 2030. We believe that the LCFS is a critical program driving down the harms to our air, our climate and communities most impacted by fossil fuels

…

2030 Target - Establish a 2030 Carbon Intensity Target of 22 Percent or More

Our organizations appreciate that the proposal takes a stronger approach to the 2030 target than the 18 percent reduction envisioned in the 2030 Scoping Plan. CARB's AB 32 Environmental Justice Advisory Committee recommended that the target be set at 30 percent.[2] Further, recent research suggests that even a 22 percent target for 2030 could be viewed as conservative.[3] We believed that the Scoping Plan was far too conservative and that the current proposal should by adjusted to achieve at least a 22 percent reduction in carbon intensity by 2030.

[2] California Air Resources Board. AB 32 Environmental Justice Advisory Committee. "Recommendations for Proposed 2030 Target
Scoping Plan Update." March 2017. https://www.arb.ca.gov/cc/scopingplan/2030sp_appa_ejac_final.pdf

[3] Cerulogy. March 2018. "California's Clean Fuel Future: Assessing Achievable Fuel Carbon Intensity Reductions Through 2030."
https://www.ucsusa.org/press/2018/scientists-say-california-can-get-tougher-clean-fuels#.WsacBy7waUk

In closing, we support the vision offered in the proposal to exceed the target considered in the 2030 Scoping Plan, but encourage the board to pursue a stronger target for 2030. (HMO1_113-1)

Comment: We write in strong support of an ambitious strengthening and extension of the program through 2030; the LCFS plays, and must continue to play, a key role in the state's efforts to reach its climate targets. Based on evidence provided by several recent fuel availability assessments performed by independent consultant Cerulogy and, separately, ARB staff, **we urge the ARB to advance a LCFS program with a 2030 Carbon Intensity (CI) target of at least 22%.**

…

However, based on recent fuel availability assessment completed in March 2018 by independent firm Cerulogy and additional supporting analysis, including modeling provided by ARB in the ISOR, we believe that a 2030 20% CI target is unnecessarily weak and fails to take advantage of the full potential of the low carbon fuel market. Based on current analyzes, we support a 2030 CI target of at least 22%, with increasing stringency in the later years of the decade.

Cerulogy's analysis - *California's Clean Fuel Future: Assessing Achievable Fuel Carbon Intensity Reductions Through 2030* - finds that California could potentially increase its LCFS target in 2030 by as much as 25 percent—and spur more rapid deployment of clean fuels. The study evaluates a range of potential LCFS credit scenarios. The Steady Progress scenario, a conservative estimate of fuel availability, assumes that fuel supplies develop at a moderate pace and the LCFS credit bank retains a balance essential for the health of the program. This scenario yields feasible reductions of 22% by 2030 when program stringency is increased after 2025. Given that this scenario did not account for the full potential of all credit generating pathways, including the use of renewable energy to charge electric vehicles, a 22% CI target is clearly a realistic goal. The High Performance scenario considers the effect of feasible future policies and innovation which allow fuel supplies to develop at the upper end of

their likely range. It finds 2030 reductions above 25 percent are possible. Given these findings, and the success of the program to date, we urge ARB to direct staff to set a more ambitious 2030 target of at least 22%.

Our support is firmly grounded in economic reality. We know that tackling climate change is one of America's greatest economic opportunities of the 21st century and we applaud California's leaders for taking steps to help the state seize that opportunity. As successful businesses, we know the importance of recognizing and seizing opportunities. Given the importance of the LCFS in reducing carbon emissions, promoting fuel diversity, reducing public health impacts, and driving economic development in the state – and recent supporting fuel supply analysis – we strongly support ARB adopting an ambitious, yet feasible post-2020 LCFS program with a 2030 CI target of at least 22%. (BICEP1_11-1)

Comment: EDF fully supports extending the LCFS program to attain reductions from the fuel sector past 2020 and believes that continuing the LCFS policy with more stringent targets is imminently achievable. As documented by Dr. Chris Malins in a recent report sponsored by the NextGen Policy Center, the Union of Concerned Scientists and CERES, compliance with the LCFS is achievable at even lower carbon intensity targets than previously assumed due to the growing availability of low carbon options in fuel production and use. Therefore, while year-over-year compliance targets in the rule continue to be (and should be) the subject of review, it is clear that lower carbon intensity targets can be achieved and the use of mechanisms in the LCFS to inspire and reward investments across the fuel production, transportation, delivery, and use value chain will be increasingly important and make compliance by fuel providers increasingly attainable. For example, through the development and use of tools such as a cost control mechanism, carbon capture and storage (CCS) protocol, refinery investment crediting opportunity and electric vehicle crediting refinements, long-term compliance with the LCFS reduction trajectory is achievable at levels well below the original 10% average fuel carbon intensity (AFCI) reduction target. Although staff has proposed a 20% reduction target for the year 2030, we assert that staff should explore setting a target above 20 percent by 2030. (EDF1_48-2)

Comment: We support a 2030 target for reducing the carbon intensity of transportation fuels by 22% or more. Such a target is achievable by continuing the growth of alternative fuels. The LCFS will make a major contribution to California's efforts to reach its 2030 standard of reducing greenhouse gas emissions by 40% from 1990 levels by 2030. In addition, a strong LCFS will reduce the localized air pollution, caused primarily by combustion of fossil fuels for transportation, that continues to damage the health of millions of Californians. (CCA1_52-2)

Comment: CARB staff's proposal to increase the 2030 carbon intensity reduction target to 20 percent is positive, although the science shows an even higher target is feasible, and we recommend that staff further explore setting a target above 20 percent by 2030. On the 2020 target, staff's proposed reduction goes too far, and we urge a second look at the proposed interim targets.

The ISOR's proposed 20 percent carbon intensity reduction target by 2030 improves upon the 18 percent target described in the Scoping Plan. The more ambitious target is readily achievable, and supports investment in low-carbon fuel production and distribution infrastructure. Moreover, the proposal's steady 1.25 percent increase in annual carbon intensity reduction targets addresses in some measure concerns we had about the adverse market signal sent by the plateau at 10 percent from 2020-2022 in earlier proposals….

…

On the longer term target, the science is clear: We can go beyond 20 percent in 2030. Recent analysis by the UK-based independent research firm Cerulogy[4] finds that California could feasibly increase its LCFS target in 2030 to well over 20 percent and spur more rapid deployment of clean fuels. The study evaluates a range of potential LCFS credit scenarios. Under moderate assumptions, research indicates there will be ample supplies of low carbon fuel and credit generation opportunities to support a 2030 carbon intensity reduction target of approximately 22 percent. If fuel or technology markets develop toward the higher end of their potential range, targets as high as 25% are feasible. In light of the Cerulogy analysis we recommend that staff further explore setting an achievable target above 20 percent by 2030. Adopting a target above 20 percent would send a more robust price signal to incentivize producers, reduce carbon dioxide emissions by millions of tons and incentivize the deployment of advanced, clean transportation technology.

[4] "California's Clean Fuel Future Assessing Achievable Fuel Carbon Intensity Reductions Through 2030," Chris Malins, Ph.D., Cerulogy Consulting, March 2018. https://nextgenamerica.org/californias-clean-fuel-future/

(COALITION1_107-3)

Comment: We also strongly encourage the 2030 target to be increased to 22 percent. California have historically lead the nation in ambitious environmental policy, and now is not the time to ease up. (CNGVC1_118-2)

Comment: In general, NextGen **strongly supports the re-adoption of the Low Carbon Fuel Standard through 2030**, with an increased CI reduction target. For the most part, we find the analysis presented by the LCFS team to be extremely high-quality and compelling. Except where noted in this letter, we support re-adoption of the LCFS consistent with the Draft ISOR and proposed regulatory text.

The LCFS Should Be Re-Adopted With A 2030 CI Reduction Target No Lower Than 23%

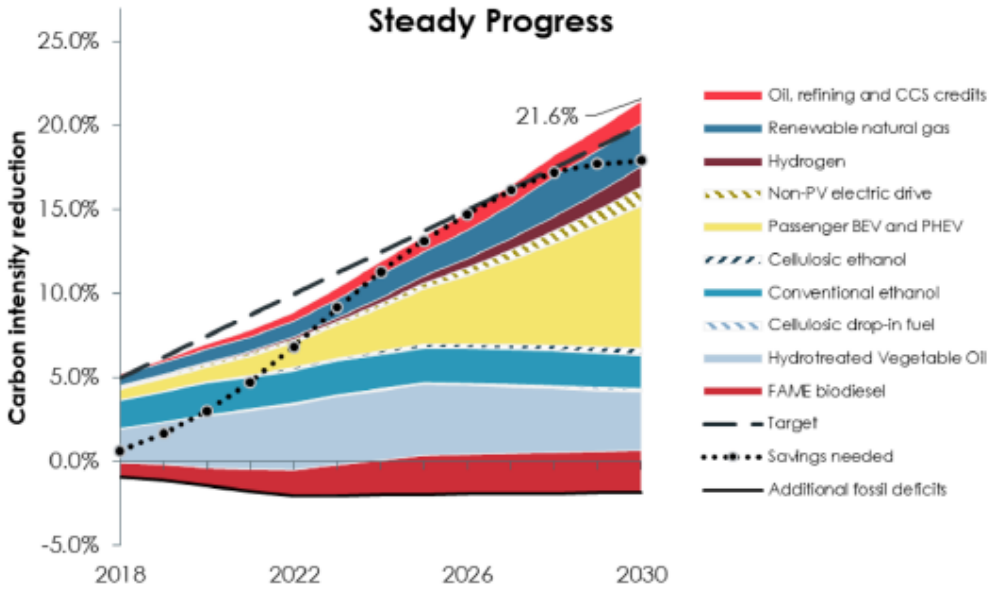
Staff have proposed that the LCFS be re-adopted with CI reduction targets increasing by 1.25% per year from 2019 through 2030, to arrive at a 20% CI reduction target by 2030. We feel that this proposal is, in general, an improvement on the trajectory described in pre-rulemaking workshops, which proposed a maximum CI reduction target of 18%, with a rapid ramp up to 2020 followed by several years of static targets before resuming target increases. We think that the proposed target trajectory can be improved upon however.

NextGen urges the Board to instruct staff to develop one or more proposals for more rapid increases in the CI target, for the Board to consider prior to its second vote later this year. These proposals should Recent analysis, which will be discussed in the following section, indicates that there is ample fuel capacity to support a significantly higher reduction target, which would support investment in innovative clean technologies and prevent millions of additional tonnes of carbon pollution from entering the atmosphere. The Board must take action now to begin the process of evaluating and adopting a more appropriate CI target for 2030.

California's Clean Fuel Future

This recommendation is based on the research report *California's Clean Fuel Future, Updated: Assessing Achievable Fuel Carbon Intensity Reductions Through 2030*, by Dr. Chris Malins of Cerulogy, sponsored by NextGen, Ceres and the Union of Concerned Scientists.[6] This report evaluates likely low carbon fuel development under a variety of reasonable technological and market conditions over the next twelve years to assess potential supplies of low-carbon fuel and LCFS credits. The report concludes that under moderate assumptions, there are ample supplies of fuel to support a 2030 CI target significantly higher than the 20% proposed by staff.

[6] Available at: nextgenamerica.org/californias-clean-fuel-future/

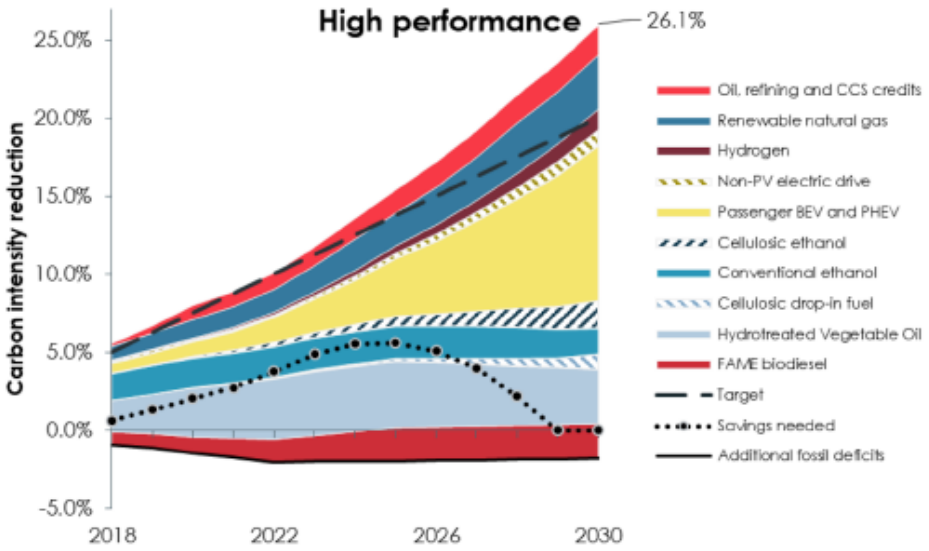


The *Steady Progress* scenario reflects assumptions about fuel pathway development that are in the moderate part of the potential range of outcomes for each fuel. It assumes that existing state policies continue to develop as planned, but does not assume any significant Federal or State policy actions, nor any transformational market shifts towards clean energy or fuels.

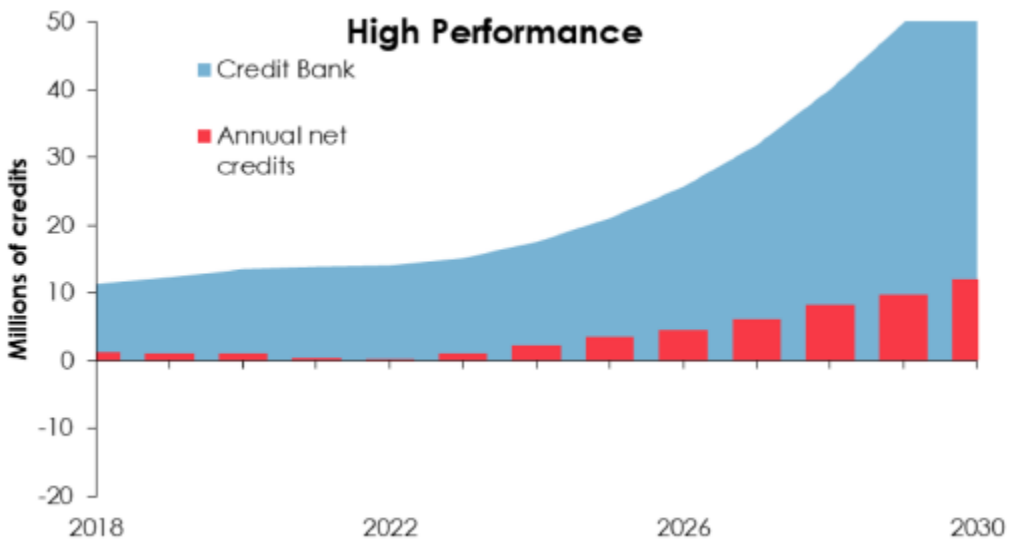
The *Steady Progress* scenario differs from the scenarios modeled by Staff in the illustrative compliance scenario calculator in several key ways. It assumes that the state will meet the Zero-Emission Vehicle (ZEV) deployment target of 5 million vehicles,

set by Governor Brown in Executive Order B-48-18. It also assumes slightly greater utilization of new LCFS credit generation pathways relating to investments in clean refineries, and a slightly faster decarbonization of the California electricity grid based on recent projections in the IEPR.

Given California's commitment to clean fuels and transportation, CARB's broad authority to adopt policy under SB 32 and other statutes, and the history of rapid development in the clean transportation sector over the last two decades, we think that the *Steady Progress* scenario represents the lower limit of state ambition. It is, essentially, the least California could do to reduce emissions and clean up transportation. We anticipate that California will continue its leadership in both technological development and climate policy. The State Legislature has made a strong and durable commitment to clean transportation as a major recipient of funding from the Greenhouse Gas Reduction Fund and there have been dozens of bills in the last several Legislative sessions aimed at furthering the deployment of clean vehicles and fuels. Consumers are becoming more aware of, and more interested in, alternatives to petroleum-fueled transportation. Accordingly, the deployment trajectory of key clean transportation technologies are likely to exceed those reflected in the *Steady Progress* scenario.



NextGen believes that the *High Performance* scenario better reflects what California can reasonable achieve in the next decade. This scenario reflects more rapid deployment of some technologies, notably a total of 5.8 million ZEVs by 2030 and greater deployment of electric and renewable natural gas vehicles in the medium and heavy duty sectors. Under a 20% target, the technology deployment modeled by the *High Performance* pathway massively over-performs LCFS requirements. This would results in a massive bank of credits accumulating by 2027, which would likely drive LCFS credit prices significantly downward and stifle ongoing investment that would be necessary to attain post-2030 goals (See Figure, below).



We note that the *High Performance* scenario is still far more conservative than the maximum technical potential across all low carbon fuel pathways. For example, the assumption of 5.8 million ZEVs by 2030 is based on a bounding scenario developed by the California Energy Commission, but is lower than the 7 million ZEVs assumed by Southern California Edison in its Deep Decarbonization Scenario or similar ZEV deployment trajectories modeled by Bloomberg New Energy Finance or Navigant, which were cited in the recently adopted Scoping Plan. The *High Performance* scenario also assumes minimal credit generation from electric medium and heavy duty vehicles prior to 2024; recent commitments by major transit agencies to procure electric buses will likely yield more MD/HD electrification credit than this scenario assumes, by themselves. The *High Performance* scenario also assumes significantly lower consumption of alternative distillates, such as renewable diesel and renewable jet fuel, than any of Staff's scenarios with a 20% or higher CI target. We also note that the *High Performance* scenario assumes a modest contribution from carbon capture and sequestration, of around 1.5 million tonnes of carbon dioxide between refineries and conventional ethanol facilities in 2030. More significant deployment is quite feasible under likely credit prices through the next decade, which would result in significantly more credit generation than is modeled here.

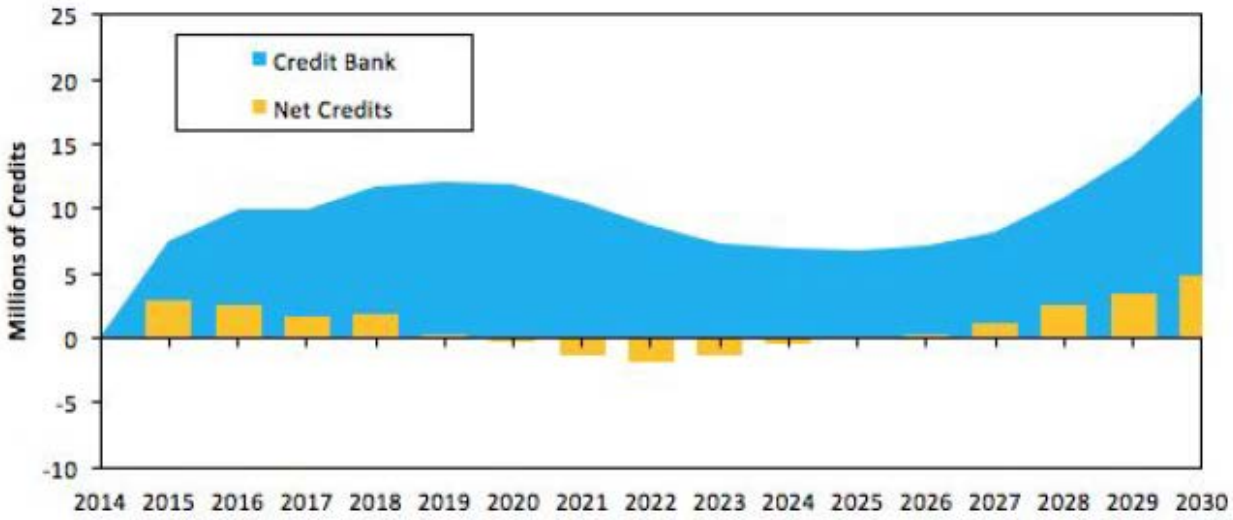
The Rationale for a 23% Target

NextGen is submitting our projection of future fuel deployment under a 23% 2030 CI target as a completed custom profile in the Illustrative Compliance Scenario Calculator, attached to this submission. Our proposed target trajectory is given below:

Year

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
6.40%	7.80%	9.20%	10.60%	12.00%	13.40%	15.00%	16.60%	18.20%	19.80%	21.40%	23.00%

This trajectory, when applied to the *HIgh Performance* credit generation trajectory using our High-VMT assumption yields the following credit bank projection:



This reflects modest continued growth until after 2020, at which point the substantial bank of credits that accumulated during the period of frozen CI targets in 2015-2016 is gradually spent down until the mid-2020's, when ZEV deployment reaches high enough levels that the non-linear effect they generate begins to dominate the system, resulting in robust credit bank growth and a program well positioned to continue its ambition after 2030. The credit bank drops to 6 million tonnes in 2026, or almost 50% of expected obligations, which represents a strong reserve against unexpected challenges. The robust bank of credits will insulate this trajectory against under-performance by some technologies or fuel demand above even Cerulogy's High-VMT scenario.

Critically, the 23% target ensures a robust and predictable demand for LCFS credits in the latter years of the re-adopted program, which will give investors confidence to make major commitments of capital now, with the expectation that their investment will benefit from LCFS credits throughout the next decade.

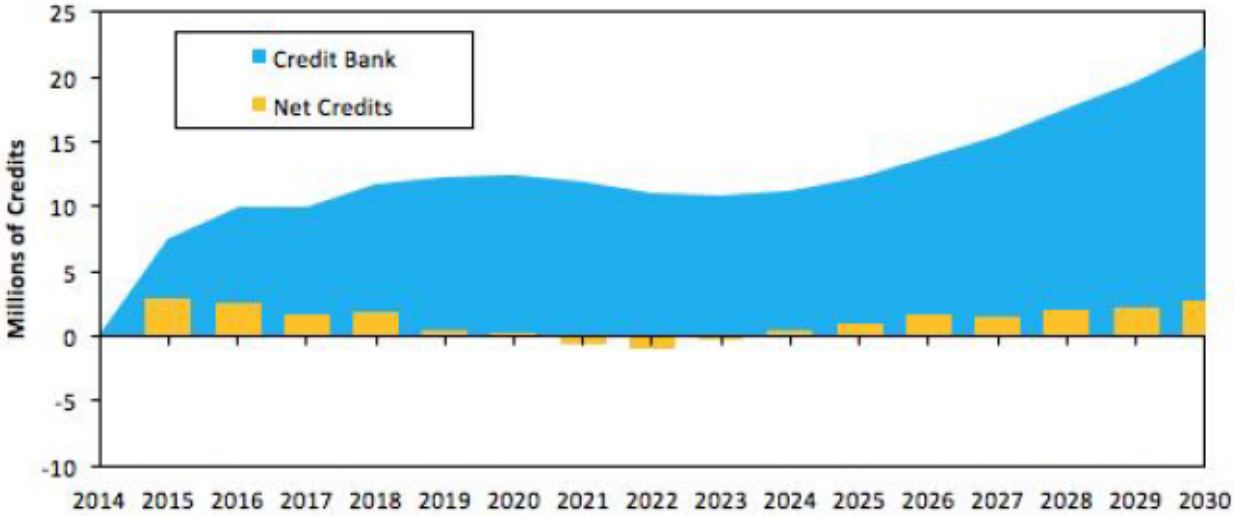
A 24% Target is Also Feasible Under the Same Assumptions

The Cerulogy research indicates that credit generation under likely technological pathways tends to accelerate in the latter half of the next decade. Absent a commensurate increase in targets, this could result in the development of a substantial bank of credits which sends challenging market signals to prospective low-carbon fuel project developers considering major capital investment projects which would require a long payback. The 23% scenario proposed above includes increases in CI targets of 1.4% per year through 2024 and 1.6% per year thereafter. By shifting the CI target schedule to a slower 1.3% per year growth rate during the early years of the program, a 24% 2030 target can be reached without preserving a bank of at least 10 million credits throughout the duration of the program. Like the 23% trajectory above, the fuel demand modeled in this analysis is the more conservative High-VMT case.

Year

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
6.30%	7.60%	8.90%	10.20%	11.50%	13.00%	14.50%	16.00%	18.00%	20.00%	22.00%	24.00%

This trajectory yields greater emissions benefits in 2030 and beyond and more closely matches expected credit generation patterns, though the 23% trajectory in the previous section delivers greater near-term emissions benefits and a presents a more stable yearly rate of target increase. **NextGen suggests that in addition to the 23% target trajectory presented in the previous section, Staff also consider a back-loaded 24% trajectory as shown here.**



(NEXTGEN1_124-5)

Comment: *Higher LCFS CI Targets Support California's Broader Climate Policy*

The LCFS should be considered not just as an independent policy, but as one element of California's portfolio of climate change policies. The LCFS constructively interacts with almost every other element of climate policy, by reducing the number of Cap-and-Trade permits consumed by the transportation sector, supporting the deployment of clean vehicles, providing a market for RNG that would otherwise have been lost as fugitive methane from dairies or organic waste disposal, and providing flexible demand on the grid to support renewable electricity. In almost every case, the synergistic interaction between LCFS and other climate policies is improved under a higher target.

The LCFS' effect on the cap and trade market is particularly important to consider. As the LCFS replaces high-emitting petroleum with low-emitting alternatives, fuel providers will be obligated to buy fewer allowances to cover emissions from their fuels. This will tend to put downward pressure on cap-and-trade allowance prices and minimize the risk that additional allowances will be released from the cost containment reserves. In the absence of strong complementary policies to reduce emissions from the transportation sector there will be significant upward pressure on allowance prices. during the

2020-2030 time period. The LCFS will moderate this upward pressure, resulting in lower cost of compliance for all entities with a compliance obligation. ICF International's 2016 report supports this intuitive understanding of the dynamics between LCFS and Cap-and-Trade, they estimated that a 20% LCFS would reduce cap-and-trade allowance prices by $29 compared to a 10% target.[7] Neither NextGen nor ICF claim that the savings from lower allowance prices would fully offset the costs associated with a higher LCFS target, however it is clear that these savings would significantly mitigate such costs.

It is also important to note that the LCFS typically causes lower fuel price impacts to consumers than a Cap-and-Trade program of equivalent stringency. Under the Cap-and-Trade program the full marginal cost of emission allowances can be expected to be passed through to consumers, whereas only a fraction of the marginal cost of LCFS credits are expected to be passed through, proportional to the CI reduction target. For example, most retail transportation fuels are blends of petroleum and lower-carbon biofuel, such as E10 (10% ethanol, commonly sold as retail gasoline) and B5 (5% biodiesel, commonly sold as retail diesel). In blended fuels, the high-carbon fraction of each gallon functionally subsidizes the low-carbon fraction through LCFS credit transactions. Producers see the price-based incentive to reduce emissions, but only a fraction of that price reaches the consumers, which minimizes the impact on prices at the pump. LCFS therefore offers the chance to reduce transportation emissions with less price-base impact on consumers and less risk of regressive effects than relying more heavily on Cap-and-Trade.

Numerous stakeholders, including NextGen[8], have expressed concern that the recently adopted Scoping Plan assumes, without sufficient justification, massive reductions in emissions driven by the Cap-and-Trade Program. Complementary measures yield a much smaller fraction of total emissions than in previous years. Increasing the LCFS CI reduction target would reduce the burden on the Cap-and-Trade system by driving emissions down through complementary measures. Each percentage point of additional CI target yields 3-5-million tonnes of additional cumulative carbon pollution reduction through 2030 when phased in over the last 5 years of the program. The proposal we offer above would be expected to reduce emissions by a cumulative 16 million metric tons, compared to CARB's suggested 20% target.[9]

[7] http://www.caletc.com/wp-content/uploads/2016/08/Final-Report-Cap-and-Trade-LCFS.pdf

[8] See: https://www.arb.ca.gov/lispub/comm2/bccomdisp.php?listname=ct-3-2-18-wkshp-ws&comment_num=28&virt_num=22

[9] This value determined by summing total credit generation from CARB's 20%, High-ZEV, High-Demand scenario, and NextGen's Suggested Compliance Scenario. The difference between the two is 16 million metric tons.

(NEXTGEN1_124-18)

Comment: The area that I really want to spend most of my time focusing on is on the subject of targets. And NextGen believes that the 20 percent target is errors on the side of being too conservative, and that a higher target is in fact feasible under likely fuel supplies under a wide variety of technological and economic scenarios. And our opinion has been informed by research. NextGen, Ceres, and Union of Concerned

Scientists have sponsored a research effort that resulted in a report which we have submitted to the docket, including update to reflect the March 9th changes. That research was conducted by Dr. Chris Malins who was a part of LCFS advisory panel originally and is an expert in the field. And he has found that there is in fact sufficient fuel to support targets significantly in excess of 20 percent.

We have suggested a 22 -- I'm sorry -- a 23 or 24 percent target depending upon a preference towards a linear trajectory or towards following the actual deployment of zero-emission vehicles. But one thing we noticed on -- across all the scenarios we looked at was in the later years of the program the deployment of zero-emission vehicles meant you had quite a few additional credits coming on to the market, and potentially sending a signal to producers who'd like to make major capital investments that the credit price might not be high enough to support those investments later.

This is the one opportunity we have to go and allow producers to make major investments that require a decade-long payback.

I would also point out that a higher target takes a lot of pressure off the cap-and-trade market and other elements of California's broader climate policy. The more missions that we can get out of the transportation sector through a feasible and cost-effective measure like the LCFS, we think that it goes and supports broader climate policy in California and supports us attaining SB 32 targets using the kind of innovative technologies that have already been proven to work through the Low Carbon Fuel Standard.

So we think that -- again, what we're asking is that you request that staff produce some proposals for higher targets than the 20 percent that can be discussed in depth over the summer. We think that the trend of the research so far has been to sort of narrow the possible range. We think the range shows now that 20 percent is really the very sort of bottom end of reasonable ambition that California should have with regards to this program. And we would like to have a discussion about what the more appropriate number would be, and we think that is somewhere in the 22 to 24 percent range. (NEXTGEN_T25-2)

> **Agency Response:** Staff acknowledges that achieving higher CI reduction targets may be technically possible, but estimates that implementing a higher target will come at a much higher economic cost. The economic analysis of the proposed amendments conducted by staff in preparation of the SRIA and the ISOR both assessed an alternative where the target CI reduction is set at 25 percent by 2030 (called Alternative 1 in both cases). The economic analysis in the ISOR estimated the direct cost of complying with the proposed amendments for deficit generators to be $9.0 billion from 2019 through 2030. Setting the CI reduction target to 25 percent was estimated to increase the direct cost of complying to $38.5 billion cumulatively from 2019 through 2030, which translates to almost a quadrupling of the direct cost of compliance.

Many comments that called for higher annual CI reduction targets refer to the April 2018 Cerulogy report titled *California's Clean Future, Update: Assessing Achievable Fuel Carbon Intensity Reductions Through 2030*. Staff appreciates the report and will consider the information provided in the report to conduct more informed analysis of fuel availability and LCFS credit generation over time.

That being said, staff's and Cerulogy's analyses differ substantially in several key points. The most important difference between Cerulogy's analysis and staff analysis arises from Cerulogy assuming a much higher rate of deployment of zero emission vehicles (ZEVs). Other assumptions that Cerulogy make are also more optimistic than staff's and are discussed in the assessment below.

First, the Cerulogy study assumes a much larger number of ZEVs (4.8 million ZEVs in the steady progress scenario and 6.4 million ZEVs in the High ZEV scenario) to be deployed by 2030 compared to the staff's analysis (2.8 million ZEVs in the main scenario, and 4.2 million ZEVs in the high ZEV scenario described in Appendix G of the SRIA). Staff chose to model the lower number for the main scenario because "the Scoping Plan targets for ZEVs are not a part of any existing legislation or mandate" (ISOR, Appendix E, Pg. 89). Cerulogy's assumption of higher ZEV number results in a higher estimate of electricity and hydrogen used, and thereby greater number of credits generated from electricity and hydrogen. While staff's analysis estimates that light-duty electric vehicles will generate 5.0 million credits in the main scenario in 2030 (10.3 million credits in the high ZEV scenario), Cerulogy's analysis estimates that 16.8 million credits will be generated in their high performance scenario in 2030.[8] Cumulatively from 2019 to 2030, Cerulogy's analysis assumes that light-duty ZEVs will generate additional 53.9 million credits in comparison to staff's main scenario (additional 34.9 million credits in comparison to staff's high ZEV scenario).[9] Staff's ZEV estimates for the main scenario for 2019 through 2025 are based on CARB's Advanced Clean Car Midterm Review report, which estimates that California will have 1.2 million ZEVs by 2025. Staff assumed that for 2026 through 2030 ZEV car sales will stay constant from 2025 onwards. As mentioned above, staff made this assumption because there is currently no legislation or mandate which will ensure the higher adoption rates assumed by Cerulogy, and no studies or reports are provided by the commenter to justify the higher assumption.

[8] To view the comment and download the illustrative compliance scenario submitted by Nextgen, please visit:
https://www.arb.ca.gov/lispub/comm/bccomdisp.php?listname=lcfs18&comment_num=145&virt_num=124

[9] Staff recognizes that hydrogen from HDV was combined with hydrogen from LDVs thus the calculation above slightly overestimates the difference between Cerulogy and staff's estimates. However, this does not change the discussion above, because the difference between Cerulogy's and staff's estimates is largely driven by credit generation from battery electric and plug-in hybrid LDVs, with a smaller contribution from fuel cell vehicles.

Another area where staff's analysis and Cerulogy differ is the size of the demand of natural gas used for transportation. The Cerulogy scenario assumes that natural gas demand will increase to 573 mm DGE by 2030, while staff's analysis assumes that natural gas demand will be 319 mm DGE by 2030. In fact, Cerulogy's scenario assumes that natural gas demand will reach 341 mm DGE by 2020, nearly equal staff's estimate for the size of the demand of natural gas for transportation by 2030 and more than double the current natural gas demand for transportation in California. Staff's estimate is within the range of the California Energy Commission's (CEC's) latest forecast, lying between the Mid and High demand cases.[10] Ceruloy's estimate of the size of natural gas demand is 30 percent higher than CEC's High demand case. In fact, Cerulogy estimates that the size of natural gas demand to reach 242 mm DGE in 2017, while the actual volume reported to the LCFS was 158 mm DGE in 2017. However, staff's estimates that a greater amount of renewable natural gas can be produced from dairy biogas, which has a much lower CI than alternative sources of renewable natural gas, such as landfill renewable natural gas. Cumulatively from 2019 through 2030, Cerulogy estimates that use of RNG in the State will generate an additional 4.9 million credits versus staff's main scenario.

Cerulogy also assumes that cellulosic ethanol will ramp up production rapidly, reaching to 0.5 billion gallons by 2030. Staff acknowledges the positive developments in cellulosic ethanol in recent years; however, staff believes that there is no strong evidence to suggest that cellulosic ethanol production will increase at the rapid pace proposed by the Cerulogy report. For instance, according to data from Environmental Protection Agency's (EPA's) federal Renewable Fuel Standard, the total U.S. consumption of cellulosic ethanol reached 10.0 million gallons in 2017. By July 10, 2018, the total U.S. consumption of cellulosic ethanol reached 5.6 million gallons, which is in line with a repeat of last year's performance.[11,12] Cumulatively from, 2019 through 2030, Cerulogy's higher assumption of cellulosic ethanol consumption results an additional 10.1 million credits versus staff's main scenario.

Cerulogy also assumes a much higher number of credits to be generated from the use of renewable hydrogen at refineries. Their estimate is based on a Stillwater Associates report which is attached to Nextgen's comment package.[13] Staff's internal analysis broadly agrees with Stillwater Associates; however, unlike the Cerulogy report, staff's analysis took in consideration the cost of

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[10] CEC, 2018. *Revised Transportation Energy Demand Forecast 2018-2030.* https://efiling.energy.ca.gov/GetDocument.aspx?tn=223241. Accessed July 25, 2018.

[11] EPA, 2018. *2017 Renewable Fuels Data.* https://www.epa.gov/fuels-registration-reporting-and-compliance-help/2017-renewable-fuel-standard-data. Accessed July 25, 2018.

[12] EPA, 2018. *2018 Renewable Fuels Data.* https://www.epa.gov/fuels-registration-reporting-and-compliance-help/2018-renewable-fuel-standard-data. Accessed July 25, 2018.

[13] To download the comment package submitted by Nextgen, please visit: https://www.arb.ca.gov/lispub/comm/bccomdisp.php?listname=lcfs18&comment_num=145&virt_num=124

bringing different fuels to market. Staff's analysis estimates that up to 1.5 million credits can be generated by refinery renewable hydrogen, but these projects require high LCFS prices ($150+) to make them economically feasible. Though it is technically feasible that refinery renewable hydrogen may contribute up to 1.9 million credits to the LCFS market annually by 2030, staff does not anticipate that LCFS credit prices will be high enough to sustain them in the main scenario. However, in the scenario that staff investigated which assumes a CI reduction target of 25 percent by 2030, staff estimated broadly similar number of credits to be generated from refinery renewable hydrogen. However, the high cost of bringing these credits to market is one of the reasons that staff believes that a CI reduction target of 25 percent by 2030 will be much more costly that the current proposal.

Overall, staff believes that the Cerulogy report makes many aggressively optimistic assumptions and does not attempt to model the economic cost of low carbon fuels production. Broadly, the Cerulogy report does not alter staff's opinion that higher targets are technically possible but come at an economic cost that staff does not deem necessary to achieve the goals of SB 32 and the State's long-term climate change goals.

A 20 percent reduction target strikes an appropriate balance between incentivizing innovation and investment in low carbon fuel production and economic effectiveness, while insuring that the State can meet its SB 32 goals in a timely fashion.

Some commenters have recommended that the CI reduction target is set at 30 percent by 2030, as recommended by AB 32 Environmental Justice Advocacy Committee. Staff has not conducted an analysis of a scenario with 30 percent CI reduction target by 2030, but as mentioned above, achieving a 25 percent target will significantly increase the costs of the proposed amendments, and increasing them even further will increase the cost even further, and may in fact not be technically feasible to achieve such targets, which has the potential to hurt the program's credibility and overall mission.

In response to NEXTGEN1_124-18, staff agrees that the LCFS and the Cap-and-Trade program were designed to be complementary, and there are potential savings in the Cap-and-Trade program due to these proposed amendments. In the ISOR and the SRIA, staff acknowledges that the proposed amendments will "benefit California fuel providers that have compliance obligations under the Cap-and-Trade Program. As the LCFS reduces the carbon intensity of fuels, it changes the composition of the State's transportation fuel mix and dependence on traditional petroleum-based fuels. CARB designed the LCFS and Cap-and-Trade Program to complement one another. Investments made to comply with one of the programs will generally result in reduced compliance requirements for the other program. Increased use of low carbon fuel due to the LCFS will reduce fuel suppliers' GHG emissions covered by the Cap-and-Trade Program, reducing the Cap-and-Trade Program compliance

obligation of these firms. Similarly, selling cleaner fuels or investing in emission reduction projects at California refineries and oil fields to comply with the Cap-and-Trade Program may help meet the project requirements of the LCFS." *(ISOR, Appendix E, Pg. 32).*

Staff also agrees that, in theory, a higher LCFS target may result in higher savings in compliance costs to entities covered by the Cap-and-Trade program. However, a more comprehensive assessment of the interaction between different CARB programs was performed under the 2017 Scoping Plan process and is not within the scope of this rulemaking.

F-2.3. Multiple Comments: *2030 Target is too High*

Comment: The 2030 target of a 20% carbon intensity reduction is very aggressive. (WSPA2_61-10)

Comment: Despite the moderated near-term targets, we believe a CI reduction of 1.25 (gCO2e/MJ) per year from 2020 to 2030 for both gasoline and diesel will prove to be a significant challenge for the producers of transportation fuels and low enough carbon intensity fuels, given the amount of time required to invest in logistic systems and construct facilities with technologies sufficient to meet these targets. (ANDEAVOR1_67-3)

Comment: Kern remains apprehensive about the post 2020 emission reduction curve and the potential disproportionate effect on smaller refineries. Specifically, Kern has concerns about ARB's aggressive incorporation of a 20% reduction in carbon intensity by 2030, despite the 2017 Climate Change Scoping Plan[1] analysis showing an 18% reduction in target as ample means to reach the State's goals by 2030. Kern is one of the smallest refineries in California, and is one of only two remaining small refineries in California producing finished transportation fuels. California Energy Commission data indicates that roughly 25 years ago a dozen small refineries operated in the state. The demise of over 80 % of California small refiners over the last 25 years is due in large part to exponentially expanding regulatory burdens and accompanying compliance costs, which disproportionately harms small businesses. Kern urges Staff to continue to consider the potential disproportionate impact on smaller facilities and ways to alleviate that burden.

[1] https://www.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf

As an example, ARB could consider applying the 18% reduction in carbon intensity to smaller facilities to help alleviate the burdensome costs of compliance. Kern's production accounts for roughly one percent of the state's total pool of transportation fuels. Granting a compliance curve of even two percent lower reduction in carbon intensity to smaller refineries, like Kern, would have negligible impact on meeting the state's goals while making a substantial difference in the facility's ability to comply. As a smaller company operating a single facility, Kern is less able to absorb regulatory costs. Notably, the reduced costs to comply in this example would create an opportunity to

utilize funds for reinvestment in the facility – investments which are critical for Kern's long term operation and success. (KERN1_115-1a)

Comment: We also believe that it is important that CARB establish carbon intensity (CI) reduction benchmarks that send a stable, long-term price signal to bring lower-carbon fuels into California

…

I. Revisit the assumptions used to establish the 2030 CI target and interim benchmarks. Based on our analysis, PG&E believes that meeting the proposed 20% CI reduction target by 2030 will be challenging as it is sensitive to policy changes, macroeconomic trends, and biofuel supplies, among other factors. We suggest CARB revisit its modeling assumptions and model additional sensitivities to better assess compliance scenarios with a lower range of targets. Additionally, we believe that a LCFS credit price much higher than $115- $135 will be needed to drive a low-carbon fuel market to achieve the proposed reductions…[W]e encourage CARB to reevaluate the 2030 target and the interim benchmarks.

…

1. Revisit the assumptions used to establish the 2030 CI target and interim benchmarks

PG&E supports the state's desire to create a LCFS that is achievable and sustainable over the long-term, and that can withstand changes in the broader economic and policy environment. In *§95484, Annual Carbon Intensity (CI) Benchmarks*, CARB has proposed to adjust the near-term benchmark schedule by linearly and annually increasing the CI reduction targets by 1.25%, from a 5% reduction in 2018 to the 20% value in 2030. This would change the 2020 target from a 10% reduction to a 7.25% reduction, which CARB notes would reduce the likelihood that the credit bank would be drawn down… However, our analysis of CARB's proposal to increase the stringency of the benchmarks to reach a 20% CI target in 2030 indicates that the program risks not meeting the CI benchmarks; thus, we recommend CARB review the 2030 CI target. As we noted in our April 10, 2017 comments to CARB on the Scoping Plan and in our September 5, 2017 comments on the LCFS Concept Paper, we were concerned that an 18% reduction target was too aggressive. Therefore, we encourage CARB to maintain the changes to the near-term benchmarks, reconsider the 2030 benchmark, and adjust the interim benchmarks accordingly.

Even with the changes to the near-term benchmarks, PG&E has identified some plausible scenarios in which entities would not be able to comply with the more stringent long-term benchmarks and put the LCFS program as a whole would be in jeopardy. For example, with a 20% target, the LCFS program is particularly sensitive to macroeconomic trends that impact gasoline demand. If gasoline demand does not drop as quickly as CARB forecasts, the program may not meet the target CI benchmarks. The program is similarly sensitive to federal policy changes to the Renewable Fuel Standard or the vehicle emission standards; revisions to these policies in ways that do

not support low-carbon fuel and vehicle adoption in line with CARB's forecasts could also result in not meeting the LCFS targets. (PGE1_120-3)

Comment: I've also examined the compliance curve in great detail and looked at what causes it to move and whether it's possible to comply, and it's very difficult. You have a lot of new fuels that will help, and you need all of them.

Some of those include new sources of renewable hydrogen from all sorts of feedstocks, including potentially manure by wire. Potentially low carbon sources of corn ethanol from sugarcane in California or from other feedstocks. And, you know, a wide variety of other fuels. (LCA5_T38-3)

Comment: I think you know this is not one of our favorite rules. You've probably heard me say that before. We still see that it's a difficult path to sustainability into the next decade.

The carbon intensity targets are pretty daunting, and there are still, we feel, some duplication with transportation fuels under the Cap-and-Trade Program. (WSPA2_T48-1)

Comment: While one recent report indicates that a "Steady Progress" scenario could reach and even exceed a 20% CI target without drawing down the LCFS credit bank, PG&E cautions that this scenario is based on several optimistic assumptions, which if not realized, could result in the credit bank being completely drawn down and several years of annual net deficits. For example, the report's "Delayed Progress" case changes just two variables from the "Steady Progress" case: cellulosic biofuel production and EV deployment.[1] As a result, the credit bank in this case is drawn down by 2023, and the program is in a persistent deficit until 2030. The report contains two other plausible scenarios in which the program's bank is depleted and persistent deficits occur.[2]

[1] In the "Delayed Progress" scenario, cellulosic biofuel production volumes stay low, with 19 million gallons of cellulosic ethanol and 62 million gallons of drop-in cellulosic fuels supplied by 2030. At the same time, electric vehicle deployment reaches the 4.2 million 2030 Scoping Plan target but not the Governor's 5 million target.

[2] i.e., the cases where passenger vehicle miles traveled (VMT) is reduced more slowly, and where the credit generation performance of liquid diesel fuel substitutes (biodiesel and HVO) is reduced by the inclusion of an indicative term for indirect emissions in the lifecycle carbon intensity values.

(PGE1_120-10)

> **Agency Response:** Staff's analysis of the supply of low carbon fuels and provisions to generate credits in the LCFS program found that achieving 20 percent CI reduction by 2030 is feasible under different scenarios, including a scenario where gasoline demand decline is slower than anticipated (See ISOR, Appendix E, Appendix H). Staff is aware that there is a probability that annual compliance targets may not be achieved in the interim years, but the LCFS provides obligated parties with flexibility to meet their annual compliance by using banked credits, participating in the credit clearance mechanism if they are out of compliance in a year, and meeting their compliance by obtaining credits in future

years (up to a maximum of five years, and accumulating an annual 5 percent interest on their account).

In response to the KERN1_115-1a comment about an 18 percent target being sufficient to meet State's goal we note that the original 18 percent target discussed in the 2017 Scoping Plan, incorporated higher interim years CI reduction target than the proposed amendments CI targets. Overall, the number of deficits that will be generated (and thus need to be offset by GHG reductions by acquiring sufficient number of credits) under both the 2017 Scoping Plan CI benchmarks and the proposed amendments CI benchmarks are equivalent within the period of 2019 through 2030. Under the 2017 Scoping Plan CI reduction schedule, staff estimates that the LCFS will generate a total of 306.5 million deficits between 2019 through 2030; under the proposed amendments CI reduction schedule, staff estimates that the LCFS will generate a total of 308.1 million deficits in the same period, or less than 0.01 percent increase in the number of deficits that will be generated by the obligated parties.

The KERN1_115-1a comment also asked if small refiners can be assigned 18 percent CI reduction by 2030 rather than the proposed amendments 20 percent CI reduction. Staff rejects such a proposal since the LCFS applies equally to all producers of fuels. However, refiners have many provisions that reduce their obligations under the original LCFS and the proposed amendments, including a provision that allows low-complexity/low-energy-use refineries, such as Kern, to reduce their products' CI.

In response to PGE1_120-10, staff interprets that the report the commenter is referring to is the Cerulogy report, which is attached to NextGen's 45-day comments. Staff has provided an analysis of the Cerulogy report in replies to comments in Section F-2.2 in this chapter. Staff has conducted its own compliance scenarios under different assumptions, and staff projects that it is unlikely for the LCFS credit bank to be depleted under staff's proposal for a 20 percent reduction in CI. Staff's illustrative compliance scenarios are available at https://www.arb.ca.gov/fuels/lcfs/2018-0815_illustrative_compliance_scenario_calc.xlsx. This spreadsheet, which is included as a reference in the rulemaking file, includes updated scenario analyses to reflect new information and changes to the proposed amendments since the publishing of the ISOR.

F-3. *2020 Target*

F-3.1. Multiple Comments: *Increase 2020 Target*

Comment: 1. The reduction in the 2020 carbon intensity target is too drastic and will cause significant market disruption.

…

1. The reduction in the 2020 carbon intensity target is too drastic and will cause significant market disruption.

As noted above, BAC members are producing many of the lowest carbon fuels participating in the LCFS program, including most of the state's dairy and diverted organic waste to fuel projects. In order to meet the state's Short-Lived Climate Pollutant requirements, California must increase the number of these projects significantly in the next several years. SB 1383 requires diversion of 50 percent of all organic waste currently going to landfills by 2020 and 75 percent by 2025.[1] That means building 100 or more new facilities to convert that organic waste to biogas and/or compost. Converting organic waste to biomethane for vehicle fuel and composting the remainder provides several times greater greenhouse gas reductions than compost alone[2] and should be encouraged as much as possible. SB 1383 also establishes a number of requirements to reduce methane emissions from dairies, including a requirement that ARB create a pilot mechanism to guarantee the long-term value of LCFS credits.[3]

[1] Health and Safety Code section 39730.6.

[2] State of Oregon, Department of Environmental Quality, *Evaluation of Climate, Energy, and Soils Impacts of Selected Food Discards Management Systems,* October 2014. Table ES-2 shows that converting organic waste to energy and compost provides 3.5 times greater GHG reductions that compost alone. Page iii.

[3] Health and Safety Code section 39730.7 (d)(1)(B).

Reducing the 2020 target for carbon intensity from 10 to 7.5 percent is a drastic reduction in the market for low carbon fuels and will impair the state's efforts to meet the requirements of SB 1383, particularly the 2020 deadline for organic waste diversion. The reduced carbon intensity target will significantly reduce the value of LCFS credits and make it much more difficult to finance projects needed to convert diverted organic waste to biomethane to meet the requirements of SB 1383.

BAC urges the Air Resources Board to reduce the 2020 target to no less than 9 percent to avoid significant market disruption for the next few years. (BAC1_99-3)

Comment: First and foremost, we are very concerned about the reduction from 10 percent carbon intensity to 7.5 percent in 2020. My members are already hearing reluctance from buyers of LCFS credits. They're concerned that the value of those credits will go down and that there will not be a market for them in the near term.

The solid waste industry in particular, which has a 2020 requirement under SB 1383 to divert 50 percent of organic waste away from landfills by 2020, they need the value of LCFS credits to remain high in the near term. The fact that they're going to go back up after 2022 is not enough.

So while some reduction in the 2020 target might be warranted, we really urge the Air Board not to go all the way down to 7.5 percent. (BAC2_T4-2)

Comment: *2020 Target - Achieve 10 Percent Reduction in Carbon Intensity*

We encourage the Board to continue to pursue attainment of a full 10 percent reduction in carbon intensity of transportation fuels by 2020. The program is working as intended

to increase the use of cleaner fuels, create incentives for zero emission fuels and maintain progress in achieving a 50 percent reduction in harmful fossil fuels by 2030. All efforts should be made to achieve the 10 percent reduction as quickly as possible and in line with the existing program goal. (VB1_10-2, HMO1_113-2)

Comment: The RNG Coalition OPPOSES the proposed amendment to smooth the near-term benchmark schedule by linearly and annually reducing 1.25 percent from a 5 percent reduction in 2018 to the 20 percent value in 2030. The value of RNG, underwritten by environmental policy and driven by monetization of related environmental attributes in associated credit markets, is highly sensitive to public policy changes, whether speculative, proposed or actually adopted. As such, the proposal to weaken the 2020 target from a 10 percent reduction to a 7.25 percent reduction has the potential to significantly undermine the market for LCFS credits generated by from RNG. **The RNG Coalition asks that CARB consider keeping the current 10 percent reduction target for 2020 in place with amendments to add a linear reduction benchmark schedule thereafter.** (RNGC1_16-1)

Comment: However, we're very concerned about the proposal to weaken the interim target to 7.5 percent by 2020. Our members have already begun to invest hundreds and millions of dollars in projects in anticipation of the current 10 percent target. To weaken the target in the middle of the process would be devastating for industry. Therefore we ask that the Board consider retaining the interim target. (RNGC2_T43-2)

Comment: The proposed regulation changes the current LCFS 10 percent reduction in carbon intensity by 2020 to 7.25 percent. This change will shrink the short-term market (3-4 years) and lead to reduced value for credits. This could have a detrimental effect on a significant number of dairy biomethane projects that are expected to come on line in the next few years. California is investing up to $260 million in dairy methane reduction efforts and many of these projects will be seeking to produce biomethane for use as transportation fuel. AECA expects as many as 70-100 projects during the next 3-5 years and as a result is concerned about the proposed reduction in carbon intensity to 7.25 percent. Without markets and long-term stability dairy biomethane transportation fuel projects will be difficult, if not impossible to fully finance. AECA recommends keeping the 2020 target at 10 percent. (AECA1_72-4)

Comment: Furthermore, we understand Staff's concerns with the near term CI reduction target in 2020 and the potential draw-down on the credit bank but Clean Energy requests that Staff keep the 2020 CI reduction target at 10%. The 10% CI reduction by 2020 was the original goal and foundation of the LCFS program from its inception. The current market supply together with the credit bank provide a pathway to achieve the 10% reduction goal by 2020, which we believe is necessary to solidify the success of the LCFS and thereby strengthen credit markets. Reducing the short term target to 7.25% sends a bearish signal to a highly sensitive and volatile LCFS market which drives cash flow for low carbon fuel producers. Additionally, reducing the current short term CI reduction creates a perpetual sense of regulatory uncertainty with respect to the path to the 2030 target and beyond. Reducing the 2020 CI target sets a bad precedent that may inadvertently call into question the 2030 (or any future) CI reduction

target, which could then undermine the LCFS credit market and corresponding project development. Clean Energy requests the Staff considers the importance of keeping the 10% CI reduction target for 2020 and implement a linear reduction of 20% in 2030. (CE1_92-3)

Comment: And I'd also like to echo previous concerns with the easing of the 10 percent of the CI by 2020, as it does create uncertainty impacting existing and future investments. (CE3_T31-4)

Comment: However, the reduction in stringency for 2019-2021 is too steep. It jeopardizes the progress the alternative fuels sector has made in bringing projects online and could chill the climate for long-term capital investment at a time when it is needed to hit 2030 targets. We urge staff to consider more ambitious interim carbon intensity reduction targets. The essential outcome is to provide a clear, strong market signal that demand for clean fuels will rise steadily and predictably over time. (COALITION1_107-3a)

Comment: CNGVC does not support the reduction of the 2020 target to 7.25 percent. We believe that with stronger policy and incentive support for ultra-Low NOx trucks, fueled with Renewable Natural Gas, California can meet that target. We already know that heavy-duty trucks exponentially cause the most pollution and if the state turns its focus to cleaning up that sector now, we can provide cleaner air for the Californians that need it most. We ask that ARB consider keeping the existing 10 percent reduction target for 2020 in place with amendments to add a linear reduction benchmark schedule thereafter. (CNGVC1_118-1)

Comment: I think the other issue that we'd like to discuss is the targets. A lot of folks have talked about the long-term targets. But the short-term targets are just as important; because, as we know, with bills like SB 1383 and other policies that are coming out of the legislature and that have already been signed into law, what we do now for projects that are happening and trying to get financed and funded to get underway, they're watching what California does and these things are affecting the market.

I know some have said that, you know, when the Low Carbon Fuel Standard proposed amendments were released there was a -- you know, some fluctuation in the market. We're not sure if that's an anomaly or not, but we also don't believe it should be taken for granted.

So we think that there could be a compromise between where we are, you know, originally from 10 percent to 7.5 percent, somewhere in the middle, and happy to continue to engage with staff. (CNGVC2_T32-3)

> **Agency Response:** In the ISOR, staff explains the need to smooth out the CI trajectory by adjusting the benchmarks for 2019 through 2021 to “achieves additional long-run GHG reductions while reducing the probability of unnecessarily high short-run credit prices, which staff’s analysis indicated may

occur if the current regulation's benchmarks are retained" (ISOR, pg. EX-3). As mentioned in Response F-2.3 of this chapter, the change from the 2017 Scoping Plan proposal of CI target reduction trajectory of 18 percent by 2030 to the CI target reduction trajectory proposed will not result in a significant change in the number of deficits that will be generated from 2019 through 2030 , while reducing direct costs of compliance by $3.4 billion.

F-3.2. Multiple Comments: *Decrease 2020 Target*

Comment: Phillips 66 recognizes that ARB is proposing near term changes in the 2019 and 2020 benchmarks, however, we believe the levels will still be extremely challenging. The 2018 data, as the year progresses, will be very informative, especially regarding credit balances and the drawdown of banked credits. The 2017 standard was a 3.5% reduction and it appears there may be a net deficit for full year 2017 (the 4th quarter data has not yet been posted). The benchmarks for 2018, 2019, and 2020 increase to 5%, 6.25% and 7.5% CI reduction from baseline respectively. These targets appear to be overly-aggressive, given the apparent difficulty in meeting the lower 2017 benchmark. It seems unlikely that credit generation will able to increase enough to overcome the changes in the benchmark (double the 2017 required percentage reduction by 2020). Further, given the challenges of meeting the near-term benchmarks, the 2030 target of a 20% carbon intensity reduction is even more daunting. We are concerned that these aspirational standards may continue to place ever-increasing costs on consumers, who already bear burdens from increased road taxes, cap and trade, RFS and other duplicative programs. We believe it essential that ARB review the program regularly and retain mechanisms to adjust, as necessary, to ensure the standards can be met. (P661_55-2)

Comment: WSPA is encouraged the proposed changes to the 2019 and 2020 compliance benchmarks in § 95484, Tables 1 and 2, reflecting stakeholder feedback. However, analysis of available fuels and potential credit generation suggest that these standards are still too aggressive and can result in widespread deficits. The proposed 7.5% carbon intensity reduction will likely be challenging for 2020 and there remains a risk of a deficit balance existing for the industry going into the next decade....

Thus, there remain system-wide constraints, at least in the short-term that make these near term standards too aggressive. These constraints include lack of low CI fuel availability (cellulosic and advanced biofuels have not developed) and time required to grow electricity fuel infrastructure and demand. (WSPA2_61-9)

Comment: First and foremost, Chevron appreciates staff's recognition that the credit bank may become exhausted in the near term given the original reduction targets. The proposed smoothing of the curve will reduce the negative impact to the fuel market in the short term. However, while the reduced obligation through 2020 is an improvement, our analysis of potential compliance scenarios shows that a 7.5% target in 2020 remains a challenging goal as there is presently no readily achievable path to a 7.5% reduction for the industry. (CHEVRON1_112-2)

Agency Response: Staff recognizes that there is a probability that deficit generation might exceed credit generation in the short run, however the LCFS design allows for the use of banked credits (which amounted to 9.9 million credits at the end of 2017) to meet annual compliance, provides a credit clearance mechanism that allows credit sellers to voluntarily participate and provide credits to obligated parties that could not meet their annual obligation, and allows obligated parties that can't obtain credits in the credit clearance mechanism to meet their current year obligations by purchasing credits in future years (up to a maximum of five years, and with an annual 5 percent interest). Staff's projection of credits estimates that the size of the credit bank is unlikely to be negative under even under the most pessimistic of scenarios that it has analyzed.

F-4. *Fuel Availability*

F-4.1. Comment: PG&E also has concern with a number of assumptions on which CARB relies in its development of a 20% CI target. For example, in CARB's recent illustrative compliance scenario, CARB assumes the deployment of around 1.35 billion gallons of renewable diesel by 2030 in addition to 500 million gallons of biodiesel. This would require roughly 35% displacement of petroleum diesel by 2030 – a significant amount since in the same scenario, CARB also assumes an additional 275 million gallons of alternative jet fuel consumed by 2030. Because renewable diesel and alternative jet fuel use similar waste-based feedstocks, PG&E is concerned that insufficient feedstock supply could threaten meeting the targets. (PGE1_120-8)

Agency Response: Staff acknowledges that there is uncertainty in the future availability of waste-based feedstock to produce biomass based diesels and alternative jet fuel. However, staff believes there is sufficient waste-based feedstock to more than meet the demand assumed by staff in the scenario analysis. According to a report produced by LMC International[14] the potential supply of global waste greases alone exceeds 10 billion gallons, far higher than California's projected demand. Additionally, two major facilities that supply renewable diesel to California are already undergoing or planning for major expansions.[15,16] Thus, the uncertainty with the biomass based diesel and alternative jet fuels is not whether the feedstock exists, but at what price point will it be sufficiently incentivized to be collected and used to supply California with

[14] LMC International, 2017. *Global Waste Grease Supply.* http://biodiesel.org/docs/default-source/policy--federal/nbb-rfs-2018-19-comments-attachment-1.pdf?sfvrsn=2.

[15] Darling Ingredients, 2017. *Diamond Green Initiates Engineering Review for Proposed Expansion to 550 million gallons annually.* https://ir.darlingii.com/2017-11-07-Diamond-Green-Diesel-Initiates-Engineering-Review-for-Proposed-Expansion-to-550-Million-Gallons-Annually. Accessed August 10, 2018.

[16] Neste Corporation, 2017. *Neste's growth program for Renewable Products takes a step forward.* https://www.neste.com/nestes-growth-program-renewable-products-takes-step-forward. Accessed August 10, 2018.

sufficient amounts to produce the necessary quantities to meet the CI reduction targets.

Staff also acknowledges that there are other uncertainties associated with staff's supply assumptions. Staff notes that any analysis that tries to assess the conditions of fuel markets for a period as long as the one analyzed will contain a certain degree of unavoidable uncertainty. However, the following reports and data support the major components of staff's analysis:

- Cellulosic ethanol: Despite difficulties in ramping up production of cellulosic ethanol in previous years, recent positive reports[17,18] from commercial cellulosic plants and increasing adoption of bolt-on technologies[19] indicate that cellulosic ethanol will play a larger role in providing low carbon fuel in California and that staff's estimates lie within the possible range that of cellulosic ethanol expansion.
- CCS projects in ethanol biorefineries: As discussed in response to GROWTHENERGY1_B4-23d in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations, staff foresees that CCS projects are economically viable at projected LCFS credit prices,[20] and staff sees a potential opportunity for many existing ethanol biorefineries to further decrease the CI of starch and cellulosic ethanol, potentially generating millions of extra LCFS credits from 2019 through 2030.
- Sugar ethanol: Sugarcane is the second leading feedstock for the production of ethanol globally, after corn starch, with production capacity from Brazilian sugarcane at approximately 10.5 billion gallons in 2016.[21] Sugarcane ethanol has, on average, a lower CI compared to corn starch. But since the biggest producer of sugarcane ethanol is Brazil, the relatively higher cost of shipping sugarcane ethanol limits the amount of sugarcane ethanol that California consumes. Therefore, staff assumes that sugarcane ethanol will provide

[17] Reuters, 2018. *2G ethanol overcoming tech glitches, competitive with oil at $70.* https://www.reuters.com/article/us-brazil-biofuels/2g-ethanol-overcoming-tech-glitches-competitive-with-oil-at-70-idUSKBN1KG30L. Accessed August 9, 2018.

[18] POET, 2017. *POET-DSM achieves cellulosic biofuel breakthrough.* https://poet.com/pr/poet-dsm-achieves-cellulosic-biofuel-breakthrough. Accessed August 9, 2018.

[19] Environmental and Energy Study Institute, 2017. *"1.5 Gen" technologies could boost cellulosic ethanol production by nearly 2 billion gallons.* https://www.eesi.org/articles/view/1.5-gen-technologies-could-boost-cellulosic-ethanol-production-by-nearly-2-. Accessed: August 9, 2018.

[20] Sanchez et al., 2018. *Near-term deployment of carbon capture and sequesterion from biorefineries in the United States.* Proceedings of the National Academy of Sciences of the United States of America. http://www.pnas.org/content/early/2018/04/18/1719695115. Accessed: August 9, 2018.

[21] United Stated Department of Agriculture - Foreign Agriculture Service, 2016. *Biofuels Annual: Brazil.* https://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Sao%20Paulo%20ATO_Brazil_8-12-2016.pdf. Accessed: August 10, 2018.

additional low carbon fuel to California only when LCFS prices are sufficiently high. Based on LCFS data reporting,[22] the maximum amount of sugarcane ethanol since 2011 that California has imported was 150 million gallons in 2013, which staff assumes to be the upper bound of sugarcane ethanol supply to California. Recent policy changes in Brazil decrease the incentive of exporting ethanol to California, and importing corn starch ethanol in its stead. First, Brazil has recently implemented an import tariff.[23] Second, Brazil is in the process of adopting the RenovaBio program which aims to increase the use of ethanol and biodiesel in domestic markets.[24]

- Electricity and hydrogen for light-duty vehicles: Staff projects that as Californians adopt greater number of ZEVs over the next decade, electricity and hydrogen use in light-duty vehicles will play an increasingly important role in credit generation under the LCFS. As discussed in Appendix E of the ISOR, in staff's Low ZEV scenario, it is assumed that California will be home to 1.7 million PEVs and 0.2 million FCEVs by 2030. In the High ZEV scenario, staff assumes that PEVs and FCEVs will number 3.5 million and 0.6 million, respectively. Together, light-duty ZEVs are expected to generate 4.96 million credits in 2030 in the Low ZEV scenario, and 10.23 million credits in 2030 in the High ZEV scenario.
- RNG: Staff estimates that there is currently enough RNG from landfills and other sources to replace all of the current fossil NG use in transportation to lower carbon RNG. A 2016 ARB funded report estimated that there is enough supply of RNG in California alone to fully convert all fossil NG used for transportation to RNG.[25] Adding the supply of RNG from out-of-state bolsters staff's assumption that RNG is expected to replace fossil NG as a source of fuel for transportation demand in California.[26]
- Dairy RNG: Staff assumes that the LCFS and RFS incentive, combined with grants from the CDFA and CPUC and a potential regulation in the future in

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[22] CARB, 2018. *LCFS Quarterly Data Spreadsheet (last updated July 31, 2018).* https://www.arb.ca.gov/fuels/lcfs/dashboard/quarterlysummary/quarterlysummary_073118.xlsx. Accessed: August 10, 2018.

[23] USDA Foreign Agriculture Service, 2017. *Biofuels Annual: Brazil.* https://gain.fas.usda.gov/Recent%20GAIN%20Publications/Biofuels%20Annual_Sao%20Paulo%20ATO_Brazil_9-15-2017.pdf. Accessed: August 9, 2018.

[24] Reuters, 2017. Brazil Senate passes bill to boost ethanol, biodiesel use. https://www.reuters.com/article/us-brazil-ethanol-renovabio/brazil-senate-passess-bill-to-boost-ethanol-biodiesel-use-idUSKBN1E62M6. Accessed: August 9, 2018.

[25] Jaffe et. al., 2016. *The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute, Contract No. 13-307*. https://www.arb.ca.gov/research/apr/past/13-307.pdf. Accessed: August 9, 2018.

[26] United States Environmental Protection Agency, 2018. *Landfill Methane Outreach Program (LMOP) – landfill technical data, landfill- and project-level data.* https://www.epa.gov/sites/production/files/2018-02/lmopdata.xlsx. Accessed: August 10, 2018.

response to SB 1383 requirements[27] for dairies and livestock operation to reduce methane, will lead to increased production of RNG from dairy waste biogas. Several dairy digester pathways are currently under review, and one dairy digester project is already generating credits under the LCFS. CDFA's DDRD program has already awarded grants to 58 dairies that plan to produce RNG that will be used for transportation fuel.[28]

- Innovative Crude Credits: Thermal EOR is used by oil producers to extract more oil from maturing fields by injecting steam into oil reservoirs. As of August 2018, there are one operational pilot scale project and one full-scale project planned in California as well as a full scale project under construction in Oman.[29,30] NRDC and Tetratech estimate the annual emission reduction potential at California oil fields from implementation of solar steam projects is 7.3 MMTCO_2e.[31] Staff's illustrative scenarios assume implementation ranging from approximately one quarter to one half of this potential.
- Refinery Investment Credits: Significant opportunities for emission reduction are also available at California refineries through implementation of energy efficiency and CCS projects and use of renewable feedstocks.[32] NRDC and Tetratech estimate an annual reduction potential of up to 7.3 MMTCO_2e from energy efficiency projects alone. Staff incorporated information from the Stillwater Associates study attached with NextGen's comment (NEXTGEN1_124) and the comment provided by WSPA (WSPA1_21) to estimate the number of credits that may be generated from the implementation of refinery investment projects. Staff's illustrative scenarios assume implementation ranging from approximately one tenth to one quarter of the potential estimated in the NRDC/Tetratech paper.
- Refinery renewable hydrogen: Staff estimates that at high enough LCFS credit prices, up to 1.5 million credits may be generated by refineries by switching the feedstock to produce hydrogen in refineries from fossil NG to

[27] Senate Bill 1383, 2015-2016, (California, 2016). https://leginfo.legislature.ca.gov/faces/billPdf.xhtml?bill_id=201520160SB1382&version-20150SB138393CHP. Accessed: August 10, 2018.

[28] CDFA, 2018. *Dairy Digester Research and Development Program.* https://www.cdfa.ca.gov/oefi/ddrdp/. Accessed: August 9, 2018.

[29] GlassPoint, 2018. *Oman Projects*. https://www.glasspoint.com/markets/oman/. Accessed: August 10, 2018.

[30] GlassPoint, 2018. *California Projects*. https://www.glasspoint.com/markets/california/. Accessed: August 9, 2018.

[31] NRDC and Tetratech, 2013. *Carbon Reduction Opportunities in the California Petroleum Industry*. https://www.nrdc.org/sites/default/files/california-petroleum-carbon-reduction-IB.pdf. Accessed: August 10, 2018.

[32] IBID.

RNG.[33] Staff estimates sufficient RNG resources are available to generate a substantial amount of credits annually.[34,35] Staff's estimate is in line with the estimate for refinery renewable hydrogen obtained in the report by Stillwater Associates which is attached to NextGen's comment (please refer to NEXTGEN1_124).

F-4.2. Comment: CARB's illustrative compliance scenario calculator also provides the opportunity to investigate several scenarios in which this situation occurs, at both 18% and 20% 2030 CI targets.[3] For example, under a "Project/Low Demand/Low ZEV/18%" fuel supply scenario at an 18% reduction target, the simulator shows a depleted credit bank by 2020 and net deficits for several years in the near future. Changing the demand scenario to "High Demand," which is not implausible given the strength of California's economy and forecasts of continued low fossil fuel prices, creates a persistent negative credit bank from 2020-2030.

[3] CARB, Illustrative Compliance Scenario Calculator, March 6, 2018, available at https://www.CARB.ca.gov/fuels/lcfs/2018-0306_illustrative_compliance_scenario_calc.xlsx

(PGE1_120-11)

Agency Response: Staff agrees with the comment that the "Project/Low Demand/Low ZEV/18%" scenario will likely result in difficulties in achieving compliance in the interim periods, and this analysis helped in informing staff's proposal to smooth the 2019 to 2021 compliance targets. The revised compliance targets show that there will likely be sufficient credit generation from 2019 through 2030 without undesirably long periods where the number of deficits generated outpaces credit generation and a smooth draw down of the outstanding credit bank.

F-4.3. Comment: While neither of the models noted in the above paragraphs consider market effects like price responsiveness to supply and demand, it is important to note that a LCFS credit price much higher than the $115-$135 that CARB estimated in

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[33] To estimate hydrogen production in California, staff relied on PADD 5 hydrogen production data from EIA (https://www.eia.gov/dnav/pet/hist_xls/M_EPOOOH_YIR_R50_MBBLa.xls. Accessed: August 10, 2019); to estimate California's proportion of PADD 5's hydrogen production, staff assumed that California's hydrogen proportion is equivalent to California's average proportion of PADD 5's gasoline and distillate production from 2013 to 2016. California's gasoline and distillate production data were obtained from CEC (https://www.energy.ca.gov/almanac/petroluem_data/fuels_watch/. Accessed: August 10, 2018), and PADD 5's gasoline and distillate production data were obtained from EIA (https://www.eia.gov/dnav/pet/xls/PET_PNP_REFP2_DC_R50_MBBL_M.xls. Accessed: August 10, 2018).

[34] Jaffe et. al., 2016. *The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute, Contract No. 13-307*. https://www.arb.ca.gov/research/apr/past/13-307.pdf. Accessed: August 9, 2018.

[34] U.S. Environmental Protection Agency, 2018. *Landfill Methane Outreach Program (LMOP) – landfill gas energy project data and landfill technical data*. https://www.epa.gov/lmop/landfill-gas-energy-project-data-and-landfill-technical-data. Accessed: August 10, 2018.

[35] U.S. Environmental Protection Agency, 2018. *Landfill Methane Outreach Program (LMOP) – landfill technical data, landfill- and project-level data*. https://www.epa.gov/sites/production/files/2018-02/lmopdata.xlsx. Accessed: August 10, 2018.

Table C1 of Appendix E[4] would be needed to drive the low carbon fuel uptake necessary to meet an 18% CI target in 2030, let alone a 20% target. CARB's macroeconomic analysis should take these higher prices into account. The cost of biofuels in particular is largely driven by the cost of their feedstock, and as competition for waste-based feedstocks increases, one would anticipate feedstock costs to remain flat or increase slightly over time.

[4] CARB, Appendix E, Table C1: Estimated Annual Credit Price for Baseline and Proposed Amendments (2016$), page 43, March 6, 2018, available at https://www.CARB.ca.gov/regact/2018/lcfs18/appe.pdf

(PGE1_120-12)

Agency Response: Staff acknowledges that there is a potential that the LCFS credit may need to be higher to generate greater supply of low carbon fuels. The prices and the economic analysis is illustrative and not definitive, as many uncertain factors might influence the cost of low carbon fuels in the future.

F-4.4. Comment: Finally, CARB's analysis looks at the macroeconomic impact of the LCFS in relative isolation;[5] PG&E recommends CARB investigate the impact of the LCFS in the context of the other relevant Scoping Plan measures to reach the state's 2030 GHG reduction goal. Assessing the cost impacts of the LCFS in conjunction with the many other policies that impact transportation fuel prices would provide a fuller view of potential cost impacts. For example, the Cap-and-Trade Program also impacts fuel prices, and will produce higher allowance prices if the LCFS fails to meet its goals.

5 Table VIII-1 in Section VIII-4 of the ISOR presents a range of potential LCFS credit price pass-through for gasoline and diesel due to the proposed amendments relative to the baseline. From 2019 to 2022, the proposed amendments are projected to reduce gasoline and diesel costs, as potentially lower LCFS credit prices are estimated for these years relative to the baseline scenario. These lower credit prices result from the smoothing of the compliance target trajectory resulting in lower compliance targets, as compared to baseline, for years 2019 through 2021. From 2025 onwards, the proposed amendments are projected to potentially increase the price of gasoline by up to $0.36 per gallon and potentially increase the price of diesel by up to $0.44 per gallon, based on the change in estimated annual LCFS credit price and annual deficits from 2025 through 2030.

(PGE1_120-13)

Agency Response: The 2017 Scoping Plan process already performed such an analysis, and staff believes performing it again in the ISOR is redundant and outside the scope of this rulemaking.

F-4.5. Comment: CARB also rapidly decreases the CI of electricity in its modeling from about 30 g/MJ (after adjusting for an energy efficiency ratio (EER) of 3.4 for light duty vehicles) to 10 g/MJ by 2022. While PG&E fully plans to meet the state's requirement of a 50% Renewables Portfolio Standard by 2030 and provide increasingly clean electricity to our EV customers, PG&E requests CARB further explain the change in the 2022 electricity CI. (PGE1_120-9)

Agency Response: The proposed amendment includes a provision that allows book-and-claim accounting for low-CI electricity used for transportation. In the illustrative compliance scenario, staff assumed that, by the year 2022, the majority of parties that generate credits from dispensing electricity for ZEVs will take advantage of this provision and reduce the CI of the electricity they dispense to generate more LCFS credits.

F-5. *Designing the LCFS to Handle Uncertainty*

F-5.1. Comment: We agree that stable targets create predictable market signals and support a healthy market for investments into low-carbon fuel production and distribution infrastructure. We disagree, however, that adopting targets below the feasible maximum and planning to adjust upwards once it is clear that the market can support higher targets is a preferable option. (NEXTGEN1_124-12)

> **Agency Response:** Staff's proposed target, as reiterated in Response F-2.2 in this chapter, represents a balance between CARB's goal to reduce the carbon intensity of transportation fuels in California and incentivize innovation and CARB's goal to do so in an economically efficient way. Additionally, the proposed CI reduction targets are consistent with CARB's 2017 Scoping Plan update process, which proposed a similar, but not identical, CI reduction targets.
>
> Staff will keep monitoring the status of technology development and deployment in the low carbon fuel space, as well as other development, and CARB retains the ability to adjust targets in the future to insure that California can achieve its broader climate change goals.

F-5.2. Comment: The Cerulogy research clearly demonstrates that there is a significant likelihood that credit generation will rapidly increase after the mid-2020's, as ZEVs become a significant fraction of the vehicle fleet. ZEVs not only generate credits through charging or fueling, they reduce deficits by displacing gasoline and generally reduce the total primary energy consumed by the transportation system, since they are several times more efficient than internal combustion engines. These effects mean that almost every scenario examined by Cerulogy indicated a rapidly growing credit bank by 2027 and in many cases, a 2030 credit balance well in excess of half the total 2030 credit obligation. Even the sensitivity cases which evaluated under-performance of the program and ran substantial deficits during the mid-2020's had regained balance by the end of the program and were on a trajectory to develop a significant credit surplus.

The fact that strong credit surpluses emerge by the late 2020's under such a wide variety of conditions will not be lost on LCFS market participants. Without a stronger target in the out years of the program, participants will perceive a very loose market in the latter years of the next decade, which will create a strong disincentive to make investments which require more than a few years to pay off, such as commercial-scale biofuel production capacity, electrical system upgrades to support high-speed charging and novel supply chains to support innovative fuels and vehicles. Potential financiers or underwriters of projects, who typically assign very little value to future policy instruments like LCFS credits at present, will see even more risk that credit prices will be unacceptably low post-2025. Conversely, a higher target, especially in the out years, creates more certainty that revenue from the LCFS credits generated by a project will remain strong throughout the full decade. Waiting for a future mid-term review or program amendment to raise targets does not create the same certainty; project developers will be unlikely to invest substantial capital in long-payback projects which depend on a favorable outcome from a regulatory action to ensure profitability. By the

time that CARB had enough data to conclusively prove that credit generation was going to exceed that required to support a 20% target and completed the necessary process to develop a higher target, it would be unlikely to be adopted before the middle of the next decade. At that point, the 2030 sunset of the program would be a disincentive to major, long-payback investments. Therefore, *now may be the only window of opportunity to encourage the development of projects with a payback period longer than five years*. To encourage these longer-payback projects, CARB needs to create the expectation that LCFS credit prices will remain stable throughout the re-adopted period; a target that is reasonably expected to under-shoot likely credit generation will not produce this result.

We recognize Staff's valid concerns about the risk of having to reduce targets. These concerns can, however, be addressed through effective and transparent program design, without the need to select an overly conservative target. Specifically, we strongly suggest staff develop a list of key metrics, and targets for these metrics, that will inform CARB's thinking about the relative balance of credits and deficits through the first half of the re-adopted program. Staff should, to the greatest extent feasible, try to create a clear expectation of whether targets are likely to increase or decrease based on the performance of these metrics. Some suggested metrics are:

- ZEV fleet size
- Average ZEV driving activity (vehicle miles traveled or VMT) per vehicle
- RNG development, including average CI
- Natural gas vehicle fleet size, which determines capacity to use RNG
- Deployment of CCS, including under-construction or contractually committed
- Fossil fuel demand
- Advanced biofuel capacity
- Status of Federal and State fuel economy or tailpipe GHG emissions standards
- Status of LCA or iLUC research, which would affect CI scores under LCFS

To be clear, we are neither suggesting nor supporting a proposal to determine mid-term adjustments purely by algorithm. There will always be a need for Staff and Board members, in consultation with the public and key stakeholders, to exercise their judgment regarding targets. CARB can minimize the risk that future adjustments send a problematic signal to market participants by creating a transparent set of metrics that can give the public a sense of whether target adjustments are likely. (NEXTGEN1_124-14)

> **Agency Response:** Staff's analysis of the LCFS credit market differs significantly from the one produced by the Cerulogy report, and these differences arise from factors described in detail in Response F-2.2 in this chapter. However, staff recognizes the possibility that the pace of credit generation might be higher than scenarios analyzed by staff due to a higher rate of ZEV adoption

by California residents, which might lead to a possibility of higher supply of LCFS credits, and subsequently lower price of LCFS credits, if targets are held constant. That said, there is also uncertainty that, due to several factors, that credit generation pace might be slower than expected which may lead to higher LCFS credit prices in the future.

Staff interprets that the commenter is suggesting that CARB adopts two sets of targets: a higher CI reduction target, and a lower CI reduction target if a combination of not achieving pre-specified metrics, public consultations and the input of the staff and Board. Staff does not see a significant difference between the commenter's suggestions and the current process by which CARB may alter future targets, except the addition of a list low carbon fuel milestones that should be achieved for the targets to potentially not go down. Staff believes that such a list is difficult to implement without giving the impression that the LCFS program is picking winners and implicitly mandating or encouraging CI reductions in certain sectors in the expense of others. Additionally, since the commenter suggests that such a list supplements a public process and the discretion of CARB, staff fails to see how such a list would substantially increase certainty for low carbon fuel producers and obligated parties.

Additionally, the commenter states incorrectly that the LCFS program will sunset by 2030. There are no statutes requiring the LCFS program to sunset by 2030; post 2030, the LCFS program will continue, and a 20 percent reduction in CI will be required. Moreover, CARB updates its Scoping Plan every five years, with the next update expected in 2022. In the next Scoping Plan Update, CARB will re-evaluate whether the LCFS 20 percent target is sufficient to achieve California's mid-century goals, or whether more stringent CI reductions are necessary to incent more rapid decarbonization in the transportation sector.

Staff agrees with the commenter that lowering uncertainty of LCFS credit prices is a desirable objective because it may lead to higher investments in low carbon fuels, eliminating uncertainty completely is incompatible with the fact that the LCFS is market-based program that will inherently lead to some level of uncertainty. This uncertainty, however, brings with it features of dynamism, flexibility and competitions between producers to achieve GHG reductions and innovation at lower prices to fuel consumers.

That said, staff does believe that CARB provides stakeholders opportunities for continuous engagement with stakeholders and a transparent decision making process for the purpose of reducing uncertainty for low carbon fuel producers and consumers, and will continue to do so in the future.

G. Credit and Deficit Provisions

G-1. *Support for the Proposed Credit and Deficit Provisions*

G-1.1. *Support for the Concept of Invalidation*

Comment: We wholeheartedly support the concept of 'invalidation' for both the cap and trade and the LCFS market. An invalidation mechanism is critical to ensure the environmental integrity of any environmental credit market. Indeed, the inability of the Clean Development Mechanism ("CDM") to invalidate offsets that were not environmentally robust was a significant factor in its demise. (PU1_37-1)

> **Agency Response:** Staff appreciates the support for the concept of invalidation in the LCFS program.

G-1.2. *Support for the Concept of Buyer Liability*

Comment: We also support the concept of 'buyer liability'. In the CDM market the liability was placed on the verifiers, who stated that they would walk away from the market if the liability was ever imposed upon them. This was why the CDM Executive Board were unable to invalidate offsets that were not robust. The concept of caveat emptor is well established and makes sense in environmental commodity markets.

We note that when developing the cap-and-trade rules the ARB took the position that "the market will find a solution to buyer liability". Accordingly, Parhelion developed a low cost invalidation insurance solution for the cap and trade market, and other providers similarly developed other solutions. (PU1_37-2)

> **Agency Response:** Staff appreciates the support for the concept of buyer liability in the LCFS program.

G-1.3. Multiple Comments: *General Support for the Proposed Eligibility of Clearing Service Provider to Opt into LCFS and the Exchange Trading of LCFS Credits*

Comment: CBL applauds the California Air Resources Board and its staff's continued support of market-based mechanisms in developing proposed LCFS amendment language that supports and encourages the expanded use exchange trading and clearing services for LCFS transactions and transfers. (CBL1_95-1b)

Comment: Adopt the proposed amendments allowing exchange clearing service provider accounts in the LRT-CBTS, and thereby allowing temporary custodial ownership of LCFS credits for clearing/escrow purposes. (CBL1_95-2)

Comment: 10. CalETC supports the draft regulation order's proposal to enable trading exchanges to participate in the LCFS market to facilitate investment in new types of credit-generating projects and seeks improvement to the language on "may not borrow

or use credit from anticipated future carbon intensity reductions" to more clearly enable future selling of credits.

…

10. *CalETC supports the draft regulation order's proposal to enable trading exchanges to participate in the LCFS market to facilitate investment in new types of credit-generating projects and seeks improvement to the language on "may not borrow or use credit from anticipated future carbon intensity reductions" to more clearly enable future selling of credits.*

The draft regulation order makes several changes to enable trading exchanges to participate in the LCFS market to facilitate investment in new credit-generating projects and alternative fuels production. This would allow new products from credit exchanges. However, the language in the current LCFS and left unchanged in draft regulation order is confusing: *"Regulated entities may not borrow or use credit from anticipated future carbon intensity reductions."* This language appears to be meant to apply to those who have deficits, but, unfortunately, the definition in the draft regulation order of "regulated entity" means that it also applies to EDUs and other opt-in fuel reporting entities. CalETC requests that this provision in the regulation be moved to an appropriate section for those who must remove credit deficits. For credit generators, CalETC requests that the regulation be clear that credit generators affirmatively may sell future anticipated credits and deficit generators may buy the different types of future credits. (CALETC1_96-13)

> **Agency Response:** Staff appreciates the commenters' support for the proposed eligibility for the clearing service providers to opt into LCFS and register an account in the LRT-CBTS to be able to transfer credits between buyer and seller for clearing purposes. Staff believes the proposed change could facilitate a transparent futures market, provide additional compliance flexibility, reduce the investment risk in low carbon fuels, further standardize the credit contracts, and result in better price discovery in the LCFS credit market.
>
> In response to CALETC1_96-13, as part of 15-day changes, staff proposed to add text in section 95487(a)(2)(B) to clarify that the provision does not preclude forward trading or contracting for future delivery of LCFS credits but prohibits borrowing of LCFS credits from future years to demonstrate compliance pursuant to section 95485(a).

G-2. *Proposed Amendments for Reporting Credit Transfers*

Comment: Some of the proposed new administrative requirements are of concern to GlassPoint. We request further review prior to the finalization of the regulation. The issues are listed below for reference. They are critical issues that GlassPoint wishes to discuss further with staff after the April 27, 2018 Board Meeting.

Section 95487(b) create new obligations to disclose the terms of a credit sale agreement that has recurring or deferred credit transfers as part of the agreement.

These obligations do not apply equally to different fuels and compliance approaches, they may require an onerous level of disclosure of commercially sensitive information, and they may pose obstacles to bringing credit-generating projects through investment to operation. Subparagraph (b)(1)(F) allowing for the Executive Officer to pre-emptively cancel pending transactions is particularly concerning. (GLASSPOINT1_65-7)

> **Agency Response:** Staff's review of credit sales information reported to CARB has revealed that the LCFS credit prices reported may not accurately represent the most current credit market as the regulation did not require differentiation between spot and forward credit transfers at the time of reporting. Further, staff proposed to add a provision that allows clearing service providers to participate in the program which could result in credits transferred for a contract arranged through an exchange or a clearing service provider (including forward deals with terms standardized by the exchange, sometimes called futures). Therefore, staff proposed to provide options to identify any credit transfers that do not represent a deal done in at current spot market conditions. This would provide detailed credit transfer information to CARB which would allow publishing more relevant information related to LCFS credit market.
>
> Staff disagrees with the commenter that the proposed changes would pose obstacle in realizing credit-generating projects or add onerous disclosure of commercially sensitive information. CARB already has access to all the credit transfers reported in the LRT-CBTS and have the authority to request more information if required. As part of market monitoring efforts, staff exercises the authority by requesting agreement details of a credit transfer that seems to have anomalous prices. The proposed change would minimize or mitigate those individual contract request.
>
> As part of the 15-days changes, staff clarified that the Executive Officer may cancel or reverse a credit transfer if it is determined to be a prohibited transaction as per section 95487(d)(1) through (6).

G-3. Multiple Comments: *Number of Days Available to Report a Credit Transfer*

Comment: In § 95487(c)(1)(C), WSPA requests that ARB allow for 5 <u>business</u> days for the Seller to post the Credit Transfer Form. (WSPA2_61-17)

Comment: 16. CalETC recommends the draft regulation order's proposal to require reporting of LCFS credit transfers in 5 days be clarified as 5 business days.

…

16. CalETC recommends the draft regulation order's proposal to require reporting of LCFS credit transfers in 5 days be clarified as 5 business days.

CalETC respectfully requests better clarity so the "five days" to report LCFS credit transfers in the draft regulation order is not interpreted to mean five calendar days, but rather five business days. Five business days is a significant improvement compared to

the current LCFS, and will allow CARB staff to do faster posting of credit transfer data. CalETC does not believe five calendar days is feasible due to holidays, illnesses, emergencies and other unforeseen events. (CALETC1_96-19)

Comment: GlassPoint also questions the need for such short reporting timelines of five (5) calendar days or three (3) business days. Multiple persons and entities will often be required to sign off jointly on reports, and such timelines appear infeasible. Why would such a timeline be necessary and how would it be beneficial? (GLASSPOINT1_65-8)

Comment: REG is both encouraged and confused by the drafted language under credit transfers in 95487(b). We think (B) is much better allowing for more flexibility. In (C), we recommend the following language:

"*Credit Seller Requirements.* Seller must initiate the documentation by completing and posting for the Buyer's review an online Credit Transfer Form (CTF) provided in the LRT-CBTS. The CTF shall contain the following fields:"

The language, "From the date of the credit transaction agreement, within 5 days," seem to imply that we will have to transfer credits within 5 days of when the agreement is completed which does not align with (B). It also does not align with common trade practices when companies will book a deal, say on February 5, for a transfer occurring during a window like Q3 (July thru September). (REG1_88-16)

> **Agency Response:** As part of the 15-days changes, staff proposed to provide a total of 10 days to the Seller and Buyer combined to report a credit transfer after the credit transaction agreement has been reached. This change would allow credit transfers to be reported more timely in the LRT-CBTS and enable CARB to publish more up-to-date information related to the credit transfers. Further, this would provide flexibility to the seller and buyer to work with each other to complete a transfer within 10 calendar days instead of providing only 5 days each to the Seller and Buyer.

G-4. *Reporting Credit Transfers*

Comment: How will (C)(8) work? Will there be optional fields when we go to transfer credits in LRT? Will there be a new form in the case of e? Will we have to input the same data for each transfer? For example, we may have more than 5 transfers on the same agreement. Will we provide the same data each time? (REG1_88-18)

> **Agency Response:** As part of the 15-day changes, staff proposed to clarify the credit transfer reporting by categorizing them in three types: *Type 1 Transfer* resulting from an over-the-counter agreement for the sale or transfer of LCFS credits for which delivery will take place no more than 10 days from the date the parties enter into the transaction agreement; *Type 2 Transfer* resulting from an over-the-counter agreement for the sale or transfer of LCFS credits for which delivery is to take place more than 10 days from the date the parties enter into the transaction agreement or that involve multiple transfers of LCFS credits over time; and *Type 3 Transfer* resulting from an agreement for the sale of LCFS

credits through any contract arranged through a clearing service provider. Staff proposed detailed reporting requirements for each transfer type. Further, for a Type 2 Transfer, the amended regulation would allow staff to assign a unique reference number that may be used for reporting future transfers under the same agreement for multiple deliveries or credits, potentially avoiding the need to input same information over and over. Options for reporting these three types of transfers will be available in a modified user interface that will be made available through the LRT-CBTS.

G-4. *Compliance Demonstration*

Comment: *§95485. Demonstrating Compliance*

REG believes the agency must define what the interest rate is going to be in 95485(c)(1)(A)(3). As a starter, we suggest prime + .25%. (REG1_88-11)

> **Agency Response:** Staff appreciates the commenter's suggestion but would like to note that the regulation is clear on the interest rate to be applied for accumulated deficits. As set forth in section 95485(c)(5)(A), a fuel reporting entities with accumulated deficit will be charged a 5 percent interest to be applied annually to all the deficits accumulated from prior compliance periods.

G-5. Multiple Comments: *Exchange Trading of LCFS Credits and Concept of Credit Invalidation*

Comment: We also recognise the ARBs aspiration to increase liquidity in to the LCFS market. In order to increase liquidity, it would be useful for LCFS credits to be listed on an exchange. Our investigations have shown that whilst potential exchanges are interested to list LCFS credits the invalidation risk makes this difficult since it means the LCFS credits are not effectively commodities. An insurance wrap would be a way to commoditise the offsets and credits, thereby enabling an exchange to list them.

Parhelion has, in response to these discussions and a number of other enquiries, been working to offer an 'invalidation risk' insurance solution for the LCFS market, analogous to our offering for the cap-and-trade market. There are however a number of barriers to this. (PU1_37-3)

Comment: Firstly, in the LCFS market, the buyer liability concept, whilst there in theory, is somewhat difficult to pin down. This makes it difficult to clearly manage this liability - "the Executive Officer retains the flexibility to invalidate the credits held by an entity other than the initial credit generator at the time of discovery". *Recommendation: that liability is clearly allocated to one party, being the current owner of the LCFS credit. Thus they will retain the ability to transfer this liability via contractual arrangements, allow market participants to choose from a range of solutions that will allow them to transfer that liability.* (PU1_37-4)

Comment: Secondly, we note that there is no tracking/serialisation of LCFS credits in the LRT-CBTS system, and that the resulting inability to track the originators of credits

and their subsequent buyers further compounds the uncertainty regarding clear allocation of liability. *Recommendation: the LRT-CBTS system be adapted to include the serialisation of LCFS credits which would remove this layer of uncertainty from credit invalidation liability.* For example, the RINS market uses unique reference numbers at the point of creation which enables tracking throughout the system.

Whilst we understand that the proposed creation of a buffer account (s. 95486(a)(3) is intended to resolve the problem where the person responsible for the credits' invalidity no longer exists, or is otherwise unable to reimburse the program, we are unable to ascertain whether the outcome of this proposal will be as intended as we do not know how many credits will fall into the categories detailed in the proposed regulations for populating the buffer account, and hence be available for retirement to offset credit invalidations.

There would also seem to be a potential mismatch between the decision to invalidate credits and the replacement of these invalidated credits from a different source to the entity responsible for the invalidated credits. Whilst this may ensure environmental integrity in so far as the number of credits in the system more accurately reflects the carbon intensity of fuel produced, it doesn't address the issue of invalidation at source and hence the problem of buyer uncertainty. Similarly, the need you refer to of the buyer having to "evaluate the likelihood of each credit generator being able to cover any invalid credits on a firm-by-firm basis" still remains. We believe that the risk transfer mechanism of insurance can solve this problem more efficiently as it allows the market to remain liquid and can remove the uncertainty surrounding credits being transferred from one party to another. Similarly, any insurance solution can be more easily assessed for its credit-worthiness since all reputable insurers benefit from transparent and publically available credit rating from rating agencies such as A.M.Best, S&P, Fitch etc. (PU1_37-5)

Comment: Thirdly, as noted above we also support your aims of increasing liquidity in the LCFS market and hence we understand why you have allowed quarterly reporting but annual verification. Whilst this does allow projects to monetise those credits generated on a quarter to quarter basis over a 12 month period, the fact that verification is done after issuance means that the perceived risk of invalidation is significantly higher than say for the cap-and-trade offset invalidation. The cap-and-trade approach of having a rigorous offset creation process BEFORE issuance significantly reduces the risk of invalidation (albeit not totally removing it). (PU1_37-6)

Comment: Lastly, we also note that the current market performance for invalidation appears to be uncertain relative to the cap-and-trade market. We believe that it would be of benefit to provide market participants with additional details of the extent of invalidation. The penalties in failing to generate credits correctly are potentially severe, with custodial sentences in the most extreme cases. *Recommendation: To inform the market better we would recommend that a table of the number of credits invalidated during each year of the program be produced.* This would be of especial benefit as the certification regime is about to change. Furthermore, we believe the number of audits carried out during each year of the program would be useful information for the market.

As the certification regime is about to change the extent of the likely burden moving forward can then be assessed. A projection of the number of audits to be carried out would provide further clarity. (PU1_37-7)

Comment: In conclusion, if the invalidation risk can be clearly allocated and therefore transferred, we believe that low carbon intensity projects would be able to monetise significantly more than 12 months revenue and market liquidity would increase. This would in turn reduce LCFS credit generators cost of funding and production. This will also lower the cost of compliance. (PU1_37-8)

Comment: While we have determined that we cannot list a futures contract which calls for physical delivery of Low Carbon Fuel Standard ("LCFS") credits that may subsequently be invalidated, we are supportive of the LCFS market and plan to list a financially settled futures contract, as previously announced on April 17, 2018.

As the ARB knows from ICE's prior comments on the LCFS program, our primary concern is that credits can be invalidated after they had been delivered. ICE appreciates the work ARB has done address such concerns, primarily set forth in the pending changes to Section 95495. However, we don't view the proposed changes as providing complete invalidation protection for unsuspecting buyers. As such, ICE is unable to offer a physical delivery futures contract on the LCFS market at this time. However, ICE intends to support the LCFS market by listing a financially settled futures contract on May 21, 2018.

The ICE futures contract will financially settle against the OPIS LCFS spot market assessment as published in the "OPIS Ethanol & Gasoline Component Spot Market Prices". We believe that this contract will provide many important features for LCFS market participants. The contract will allow for certainty and growth by providing a transparent forward curve of tradable prices which developers and financiers can use to hedge exposure. Furthermore, we anticipate broad market access which should dampen volatility and improve financial terms for compliance entities and developers. (ICE1_101-1)

> **Agency Response:** Staff appreciates the commenters' support for the LCFS credit market and insights for potential benefits and challenges associated with exchange trading of LCFS credits.
>
> Staff understands that potential invalidation of LCFS credits could make it difficult for clearing service providers to list a physically settled LCFS credit. However, credit invalidation is an important tool to ensure environmental integrity of the program in case issued LCFS credits are found to not represent valid emission reductions pursuant to LCFS rules. Staff did not propose to limit the liability of a buyer or seller in case of an invalidation event but staff did propose to add a buffer account as a risk mitigation tool for the program. The buffer account would be populated with the credits representing real emission reductions that cannot be realized under the current rules and a certain percentage of credits from Carbon Capture and Sequestration (CCS) on a proposed risk-rating framework. In case of credit invalidation, the Executive Officer would recover credits from the entity deemed responsible for the invalid credits or resulting deficits. However, if

the entity deemed responsible for the invalidation no longer exists or is otherwise unavailable to reimburse the program, the Executive Officer may retire credits available in the buffer account to address the invalidation. If the credits in the buffer account are not available to address the invalidation then the Executive Officer may explore other ways to make the system whole, including invalidating credits in the buyers' account. Staff agrees that this may not eliminate, but could help minimize, the invalidation risks for the credit buyers.

In further response to PU1_37-6, staff proposed mandatory third-party verification for credits generated under certain fuel pathways, whereas, the remaining credits would be subject to staff audits. The entities subject to verification requirements would be required to get the data reported for credit and deficits generation verified annually (or after two years if they are eligible for deferred verification). Although credits would be generated on a quarterly basis and could be subject to invalidation before annual verification, staff believes a third-party check would considerably reduce the long-term risk of invalidation for credits based on the data receiving positive verification statements. Staff believes a solution to further reduce the risk of invalidation would be to issue credits post verification based on verified accurate data.

In further response to PU1_37-5, as mentioned above, credits would be generated quarterly before the proposed annual verification of the reported data which results in potential for adjustments to the reported data and resulting credits before verification. Therefore, staff did not propose to include serial numbers or unique identifiers to track LCFS credits at this time as it could add complexity for report corrections and credit adjustments.

In further response to PU1_37-3, staff appreciates the commenter's proposal to offer an insurance offering to cover any perceived risks associated with credits due to the concept of credit invalidation.

In further response to ICE1_101-1, staff appreciates the commenter's proposal to list a financially settled futures contract for LCSF credits. Staff believes this would provide some of the benefits of a full-fledged LCFS futures market but helps to eliminate concerns related to the concept of credit invalidation.

G-6. *Exchange-Based Spot Trading of LCFS Credits*

G-6.1. Multiple Comments: *Proposal to Facilitate Exchange-Based Spot Trading of LCFS Credits*

Comment: As an operator of spot exchanges of environmental commodities, including spot cleared California Carbon Allowances (CCAs), CBL encourages the ARB to consider the benefits of cleared spot transactions as filling a niche between larger regulated entities who predominantly trade futures and the small-to-mid size entities at the forefront of alternative and renewable fuel production many of which do not have access to futures and derivatives markets.

…

We hope to make it easier for all market participants, including small and renewable fuel producers in California, to gain access to fair market value with the level-playing field that exchanges provide, even if they do not have access to futures exchanges.

…

Benefits of a Spot Cleared Market

CBL Markets intends to provide a spot market for the LCFS credit market, which will have numerous benefits to regulated parties, low carbon intensity fuel producers, investors and the program at large, as outlined in this section.

A spot market refers to a market in which products are sold for cash and physically settled immediately. Spot transactions can take place on an exchange or over-the-counter ("OTC"), with exchanges providing the most secure, efficient and cost effective means of trading.

A futures contract is a contract used by parties to transact a set of physical commodities or emissions allowances/offsets for future delivery at a particular price, resulting in the creation of an obligation to settle. Futures contracts are traded on approved exchanges and generally require that holders of futures contracts maintain cash margin accounts to safeguard all parties against movements in the market. Spot and futures markets complement each other by expanding access to exchange trading by both covered and non-covered entities of all sizes in a fair and orderly market where everyone is on equal footing.

Unlike a cap-and-trade program wherein the aim is solely to reduce CO2 emissions at identified sources, LCFS and REC programs aim to incentivize the market to invest in and develop renewable energy and fuels projects from a multitude of sources. As a result, the participants in the LCFS program, like in REC markets, are much more varied and diverse, resulting in a multitude of potential counterparties, from large multinational companies to small fuel producers. Many renewable fuel producers and credit originators like installers of electric vehicle charging stations or owners of electric forklift fleets are often smaller and newer entities that are not likely to be set up to trade futures.

Futures and derivatives exchanges, while serving an important role, require sophistication and substantial capital resources from participants in order to maintain daily cash margin requirements on open futures positions and to manage against price volatility. This is inherently more complicated for small-to-medium enterprises that might not have the staff and resources to access futures and derivatives.

Futures markets are well suited to enable large, sophisticated entities to hedge their exposure to changing prices. However, in many cases producers of renewable fuels are less likely to have the creditworthiness, balance sheet requirements or sophistication to participate in these markets. Moreover, many of these fuel producers

will seek immediate monetization of their LCFS credits as they are generated to cover operating costs and debt service. A physical, pre-cleared spot market offers a lower barrier-to-entry option for smaller entities to efficiently monetize the credits they generate, freeing up capital to invest in additional development of low carbon intensity fuels.

Lower Barriers to Entry

An exchange traded spot market ensures equal access to fair market value for all participants by enabling smaller non-covered entities, such as renewable fuel producers, and smaller covered entities, such as Community Choice Aggregators, municipal utilities and local agencies to access the market at a reduced cost without prohibitive barriers to entry. Exchange traded spot markets will provide participants in the LCFS Market (including covered and non-covered entities, credit originators and brokers):

- Standardized rules and contracts for a fair, orderly and transparent marketplace;
- Real time price discovery;
- Confidence of a secure clearing and settlement arrangement;
- Reduced long-term capital requirements associated with derivatives products;
- Market data and analytics.

CBL believes greater access and efficiency will increase confidence in the market-based components of the LCFS program, which will lead to:

- The development of a clear carbon intensity (CI) price signal for the fuel market;
- Greater efficiency in the market such that the covered entities will be able to meet their obligations efficiently with less cost to the end-consumer; and
- Increased investment in alternative fuel development, enabling least cost compliance with the LCFS program.

…

We are confident that a robust cleared spot market would be a tremendous benefit to large and small LCFS markets participants alike. Larger entities would be able to trade with smaller less creditworthy counterparties via an exchange acting as a central counterparty. Small and midsize covered entities and credit generators would be able to access fair market value without having to take a discounted price due to the pains of contracting over-the-counter for small volume transactions. To this end, we appreciate ARB's consideration of our proposed amendments to the regulations. (CBL1_95-1a)

Comment: Adopt eligibility requirements that enable both spot <u>and</u> futures exchanges and clearing services by removing the requirement of CFTC registration for spot exchanges.

…

Section 95483(a)(3)(A) CBL commends the ARB for recognizing the current regulation prevents trading on exchanges. We fully support the ARB in proposing eligibility requirements for entities that seek to provide clearing services for the LCFS credit market. We encourage the ARB and staff to adopt eligibility requirements that allow for both spot and futures clearing services and exchange trading.

The changes to the LCFS program as currently proposed would prevent spot exchanges to provide clearing services in the LRT-CBTS. Specifically, the requirement that an entity to seeking to provide clearing services be registered with the Commodities Futures Trading Commission (CFTC) as a derivatives clearing organization (DCO) would prevent the development of spot exchange trading as spot exchanges are explicitly not regulated by the CFTC. Therefore, there it is not possible for spot exchanges to meet such an obligation.

We request ARB to not apply the same requirement in 95483.1(a)(3)(A) to spot market clearing service providers, who do not operate under the jurisdiction of the CFTC.

Similar to renewable energy markets, the LCFS market is very broad with many small and medium credit generators and fuel producers that might not be able to trade futures. Therefore requirements that enable both spot and futures exchanges would provide the most flexibility and access to the wide variety of LCFS market participants and lead to greater transparency and liquidity for all participants. (CBL1_95-3)

Comment: V. Streamline credit trading so smaller entities that hold relatively modest credit volumes can more easily monetize credit volumes at market prices.

…

V. Encourage trading of small volumes of LCFS credits by enabling more trading opportunities for LCFS credits.

The ARB should allow for both spot and futures exchanges to provide clearing services for LCFS transactions. As set forth in Attachment 2, Section V, the ARB should amend the regulation to create opt-in exchange/clearing account eligibility requirements, which would create an opportunity for brokers to aggregate volumes of LCFS credits in both spot and futures transactions.

A physical spot market and futures market would be a great benefit to state and municipal agencies with charging infrastructure and load. In contrast to larger covered entities who already have the staff and systems in place for trading on futures exchanges, a physically cleared spot exchange would offer many of the benefits of exchange trading - anonymity, transparency, compliance flexibility, price discovery - without having to accept less than fair market value for their LCFS credits. When entities transact small volumes of credits and do not have enough LCFS credits to meet the minimum lot size of the futures contract they are often price “takers” in a futures market.

Futures and derivative markets are inherently more complicated and risky with embedded barriers to entry, including establishing cash margin accounts and satisfying counterparty risk assessments. Exchange traded spot markets require minimal daily operational management from participants (there are no requirements to manage futures positions, rolling or margin calls) and as such, costs are low and transparent, making prices accessible to all market participants.

An exchange traded spot market would ensure equal access to fair market value for all participants by enabling smaller entities, such as renewable energy and fuel producers, and Community Choice Aggregators, municipal utilities and local agencies to access the market at a reduced cost without prohibitive barriers to entry.

An exchange traded spot market will provide participants in the LCFS Market (including covered & non-covered entities, credit originators and brokers):

- Fair, orderly and transparent marketplace;
- Real time price discovery;
- Confidence of a secure clearing and settlement arrangement;
- Reduced long-term capital requirements associated with derivatives products;
- Market data and analytics

The inclusion of spot and futures clearing services will provide greater market access and efficiency to all sizes of covered entities, and confidence in the market-based components of the LCFS program will increase. In turn, this will stimulate investment in alternative fuel development, enabling least cost compliance with the LCFS program.

- Increased access to exchange trading will lead to increased liquidity in futures and over the counter broker market;
- Covered entities will have access to multiple venues for exchange cleared transactions, increasing liquidity and lowering costs
- The development of a clear CI price signal for the fuels market; and
- Lower transaction costs and greater efficiency in the market will enable covered entities to meet their obligations more efficiently with less cost to the end-consumer.

V. Enable greater trading of LCFS Credits

Adopt the proposed approach of allowing exchange clearing service provider accounts in the LRT-CBTS, and thereby allowing temporary custodial ownership of LCFS credits for clearing/escrow purposes. Section 95483.1(a)(3)(A) should be amended to adopt Opt-In exchange/clearing account eligibility requirements that enable spot <u>and</u> futures exchanges and clearing services. Require an entity seeking to provide futures clearing to be a licensed Derivatives Clearing Organization (DCO) registered with the Commodities Futures Trading Commission (CFTC). However, for spot market clearing

service providers, we encourage the ARB to not include this requirement as recommended in the Proposed Amendments. Such a requirement would prevent spot exchanges from offering spot clearing of LCFS credits, denying many small and medium-sized entities and fuel producers, many of whom are not able to trade futures/derivatives, the benefits of exchange trading. (SEVCG1_116-7, SEVCG2_B10-7)

> **Agency Response:** Staff appreciates the commenters' insights on the potential benefits of exchange-based spot trading of LCFS credits. Historically, all the regulated entities have been able to participate in a spot market through over-the-counter bilateral or broker-facilitated transactions. The LRT-CBTS also allows entities using brokers to conduct blind transactions. However, there has not historically been a systematic futures credit market. The amended regulation facilitates the creation of a futures credit market, should the market desire one, potentially providing stakeholders a forward credit price curve and an option to enter into long-term off-take contracts backed by the security of a clearing service provider. Staff believes this would allow project developers and compliance entities to hedge their investment and compliance risks potentially unlocking more financing in low carbon fuels.
>
> As proposed all the clearing service providers opting into LCFS must be registered with the Commodities Futures Trading Commission (CFTC) as a derivatives clearing organization (DCO). Not requiring the same for clearing service providers operating spot-only exchanges would require creating a separate category of clearing service providers. Staff did not propose creating that separate category as it would result in administrative complexity in the program which staff does not believe is necessary to further promote spot trading at this point.

G-6.2. ***Clearing Service Providers Holding Credits***

Comment: Allow spot exchanges and clearing services providers to hold LCFS units on behalf of sellers for up to 30 days to allow ample time to discover fair market value for their credits and minimize administrative burden of weekly transfers in the LRT-CBTS.

…

Section 95483(a)(3)(B) CBL encourages the ARB to reconsider the requirement that a clearing service provider only hold LCFS credits for up to 5 days in the LRT-CBTS for spot exchanges. This would benefit the market at large by:

- Allow for physical pre-clearing of sellers LCFS credits
- Eliminate counterparty delivery risk for buyers on an exchange;
- Ensure delivery of LCFS credits to buyers, maintaining anonymity between buyers and sellers

Therefore, CBL requests that the updates to the regulation allow for spot exchanges and clearing service providers to hold LCFS credits on behalf of approved exchange participants for up to 30 days. This will enable greater transparency and price discovery by giving sellers additional time and flexibility to find fair market value for their credits and monetize them securely and efficiently. (CBL1_95-4)

> **Agency Response:** Staff proposed that an opt-in clearing service provider could hold LCFS credits up to five days for clearing purposes but cannot own the LCFS credits. Staff believes five days are sufficient for a clearing service provider to facilitate a transfer between the seller and the buyer once the proposed transaction is finalized. During this period the credits held by a clearing service provider would not be available in the credit market for transferring or for retiring in the LRT-CBTS. In order to minimize the time period during which credits are locked out of credit market, staff proposed that a clearing service providers may hold credits only for up to five days after which they would be reverted back to the seller's account.

H. Buffer Account

H-1. Multiple Comments: Support for the Proposed Buffer Account Provisions

Comment: The RNG Coalition SUPPORTS the intent to ensure the environmental integrity of the program behind your proposal to create a buffer account during instances of credit invalidation by populating an account to utilize stranded credits, such as those credits remaining in deactivated LRT-CBTS accounts. (RNGC1_16-7a)

Comment: Third, we support the creation of a buffer account to maintain program integrity. (RNGC2_T43-5)

Comment: WSPA appreciates ARB's inclusion of the Buffer Account concept in the proposed regulation amendments. (WSPA1_21-13)

Comment: DTEBE supports the development of a Buffer Account for the LCFS program. The implementation of a Buffer Account should provide credit buyers with confidence and improve the liquidity of the LCFS program. (DTEBE1_56-4)

Comment: Further, we support CARB's buffer account concept as a way to reduce buyer liability in the market. As indicated above we believe there is more to do in this space but, as proposed, the concept further reduces buyer liability in the event credits are invalidated and the responsible party cannot be held accountable for credit replacement. (ANDEAVOR1_67-8)

Comment: Second, the buffer account proposal was an encouraging step to provide obligated market participants some form of insurance in the event an entity inadvertently purchased invalid credits. (ANDEAVOR2_T10-3)

Comment: 18. CalETC supports the draft regulation order's proposal to establish buffer accounts to mitigate the risk of credit invalidation and require business partner reconciliation to limit the scope of verification.

…

18. *CalETC supports the draft regulation order's proposal to establish buffer accounts to mitigate the risk of credit invalidation and require business partner reconciliation to limit the scope of verification.* (CALETC1_96-21)

Comment: Kern is generally supportive of ARB's proposal under Section 95486(a)(3) to add a buffer account to mitigate invalidation risk for credits. A buffer account is an encouraging alternative to a "buyers beware" approach where regulated parties are open to significant financial risk in purchasing compliance instruments. (KERN1_115-4)

Comment: We support the efforts of CARB staff to enhance the liquidity of the LCFS market by creating a buffer account (Section 95486(a)(3)). (EMRE1_B16-2a)

Comment: And then lastly, with respect to the provisions around buffer accounts, there's a lot of meat there, and we continue to look forward to working with staff on flushing that out so it's a workable, meaningful piece of the LCFS going forward. (REG2_T16-5)

> **Agency Response:** Staff appreciates the commenters' support for the proposed addition of a common buffer account in the LCFS. Staff believes a common buffer account could help mitigate the invalidation risk for credit buyers and safeguard the environmental integrity of the program in case of credit invalidation when the responsible entity is not available to make up for the invalidated credits. The buffer account would also provide an option to recognize and account for GHG emission reductions as a result of the LCFS program that cannot be recognized in the current rule at the time of credit generation.

H-2. Multiple Comments: *Individual Buffer Account Provisions*

Comment: WSPA believes that these concerns can be addressed through a "Reporting Entity Buffer Account" concept. Specifically, the goals of the concept would be to: (1) address the lack of retroactivity, (2) address minor deviations in actual/expected compliance values, and (3) improve liability protection for minor deviations. WSPA also believes that a Reporting Entity Buffer Account would provide some additional protection to accommodate instances where staff invalidates credits that were previously issued, traded in the marketplace and potentially used to retire individual parties' compliance obligation.

The "Reporting Entity Buffer Account" would be "funded" from four eligible potential sources of credits:

1. Previous reporting period adjustments that identify under-reporting of credits or over-reporting of obligation.
2. CCS credits (as outlined in the finalized CCS protocol)
3. Credits accruing when verification reveals actual CI performance was superior to that anticipated based on certified pathway CI values.
4. Dedicated, on purpose credit purchase in the marketplace at the reporting entity's discretion.

The Reporting Entity Buffer Account would be used to provide credits when:

1. Previous reporting period adjustments that identify over-reporting of credits or under-reporting of obligation.
2. Carbon storage facilities experience CO2 leakage/releases (as outlined in the finalized CCS protocol).
3. A shortfall is identified due to verified actual CI performance falling short of that anticipated based on certified pathway CI values.

Under the Reporting Entity Buffer Account, the sequence of steps to follow when a credit invalidation event occurs would be as follows:

1. The reporting entity that generated the invalidated credits is responsible for making up the shortfall their invalidation created. If that reporting entity has a buffer account, they may use their available buffer account credit balance to satisfy part (or all) of that need.
2. If the credit shortfall is larger than then buffer account balance, the reporting entity is responsible for acquiring credits in the marketplace to satisfy the residual.
3. If the reporting entity that generated the invalidated credits is no longer in existence and unable to make up the residual credit shortfall through market credit purchases, then the obligated party holding (or having used) the invalidated credits may use its available buffer account balance to satisfy part (or all) of the remaining credit shortfall.

The Reporting Entity Buffer account concept also entails a revision in the thresholds before administrative action is undertaken by staff. It is proposed that there would be no administrative action if a Reporting Entity's Buffer Account balance is sufficient to cover the credit shortfall at hand, regardless of the magnitude of the shortfall. If the buffer account balance is insufficient to cover the shortfall, then the criteria proposed by staff on the magnitude of the shortfall would apply (e.g., 5% deviation or 2 CI number difference between actual and pathway CI value).

The ARB LCFS Data Management Systems - comprised of two tightly integrated modules including the LCFS Reporting Tool (LRT) and the Credit Bank & Transfer System (CBTS) - already does have the capability for this type of documentation. The Reporting Entity Buffer Account usage would be limited to the applications described herein. A negative buffer account balance would, by definition, not be permissible. Credits could not be sold or transferred out of the account to another party. (WSPA1_21-16)

Comment: The second one we call Buffer Account Concept. We certainly support this concept. It greatly enhances the approach. We have an idea to enhance the approach called the reporting entity buffer account that we'd like you to consider. It fits really well in the Low Carbon Fuel Standard Data Management System, and it also allows individual participants of the program to be treated fairly and equitably. So it's something we hope the staff considers. (WSPA4_T48-5)

Comment: We conditionally support the buffer account concept with one modification. We would like any credits that are eligible for the buffer account to be first applied to any deficits discovered during verification. For example, if REG Albert Lea runs a higher CI than the FPC allows for, resulting in 500 deficits being created, but REG Newton runs a lower CI than the FPC resulting in 700 credits being created, the 500 credits from REG Newton would cover the 500 deficits at REG Albert Lea since they're both under REG Inc. with the remaining 200 credits going into the buffer account. (REG1_88-13)

Comment: Also, as suggested above, REG believes a company-wide buffer account or a conservative CI would help mitigate concerns with a higher operational CI than the certified CI. (REG1_88-23b)

Comment: Chevron is not in favor of the proposed Buffer Account concept in § 95486(a)(3) as written. Placing credits, separated from regulated parties due to report corrections or over-performance for a fuel pathway, into an industry-wide account is inequitable to those responsible for the credit generation. A better approach is the "Reporting Entity Buffer Account" concept proposed by WSPA. (CHEVRON1_112-7)

Comment: (2) *Buffer accounts*. To ensure that the benefit of outperforming a certified/verified operational CI remains with the producer and maintain the liquidity benefits of the buffer account, we propose the creation of two types of buffer accounts – a general account (similar to what is currently contemplated in the Proposed Regulation), comprised of credits from deactivated LRT-CBTS accounts and CCS projects pursuant to the CCS Protocol, and an individual buffer subaccount for the benefit of each active fuel producer, comprised of any credits arising from the difference between a producer's reported CI and the verified operational CI in any compliance year. In the event the producer's reported CI exceeds the verified operational CI in any compliance year, credits would be retired from the individual buffer subaccount prior to enforcement pursuant to Section 95488.10(a)(7).

…

As currently proposed, credits placed in the buffer account may be retired to address invalidation of credits if the person responsible no longer exists or is otherwise unavailable to reimburse the program generally. While we agree that a buffer account is great for the LCFS program, we encourage staff to further refine the concept by creating both a general buffer account for the program and individual buffer subaccounts for each active producer. While the general buffer account would be comprised of credits described in clauses (A), (C) and (D) of Section 95486(a)(3), the individual buffer subaccount would be created from any credits described in clause (B) of that section – any credits arising from a reported CI lower than the verified operational CI in any reporting year. The purpose of the individual buffer subaccount would be the same as the general buffer account (to potentially address the invalidation of credits pursuant to Section 95495), but it would do so on an individual producer level. As noted below, we are also proposing that producers be given the ability to place additional credits into the individual buffer subaccount as a means to potentially eliminate the need for an enforcement action. (EMRE1_B16-2)

> **Agency Response:** Staff appreciates the commenters' support for the concept of buffer account and commenters' recommendation to create individual buffer accounts where buffer credits can be first applied to that entity's deficits discovered during verification. Staff did not propose changes based on the commenter's recommendation but proposed a common buffer account in the LCFS program which would create an insurance risk pool requiring minimal contributions from different sources to help mitigate the invalidation risk for credit

buyers and safeguard the environmental integrity of the program in case of invalidation when the responsible entity is not available to make up for the invalidated credits. The proposed design of a common insurance risk pool ensures small contributions from multiple sources could help mitigate potentially larger invalidation risks without affecting or reducing the potential credits an entity could generate under the current regulation.

However, if the program would have to rely upon individual buffer accounts to reduce risks associated with invalidation then the contributions to the individual buffer accounts would have to be proportional to the individual risk that would result in significantly higher contributions per entity. This would affect or reduce the number of credits that an entity could receive as compared to the proposed changes because they would have to contribute more in individual buffer accounts. Therefore, staff did not propose creation of individual buffer accounts for each reporting entity or making entity specific reserves within the buffer pool.

H-3. Multiple Comments: *Concerns about the Proposed Credit Contribution into the Buffer Account*

Comment: <u>However, during instances in which real GHG emissions result from the difference between a verified operational CI and an annual Fuel Pathway Report, the RNG Coalition asks ARB to consider that credits transferred to the buffer account be limited to six months of generation, with the remaining credits given to the generator.</u> This system would leave in-tact the ability to populate the buffer account, while also creating some incentive for the generator to outperform the verified operational CI whenever possible. (RNGC1_16-7b)

Comment: However, we believe the proposal to hold all credits generated by a producer in excess of their certified score removes any incentive at all for producers to make operational adjustments to maximize environmental performance. As such, we have suggested a compromise where the first six months' worth of excess credits would be held in the buffer account, but any other credits generated thereafter could be monetized by the producer. We feel this would be win-win. (RNGC2_T43-6)

Comment: *Under these topic areas ACE submits comments regarding the proposal to establish a Buffer Account to mitigate risk of credit invalidation.*

- <u>Buffer Account</u>

We oppose the creation of a new buffer pool or account of credits and believe one of the most punitive features of the proposed regulation is the requirement to populate the buffer pool in part with real GHG emission reductions representing the difference between the reported CI and the verified operational CI from annual Fuel Pathway Reports for each fuel pathway code. This would penalize our members for investing in technologies and taking steps to reduce CI. In all cases fuel producers should be credited first for operational CI improvement and be allowed to pledge excess credits to the buffer pool only if they so choose. In this approach, unclaimed credits could be

deposited into the buffer account on a predefined schedule after allowing producers sufficient claim time. This would allow for the population of the buffer account, as deemed necessary by CARB, while also retaining the incentive for the credit generator to outperform their CI score whenever possible.

The buffer account is essentially an insurance risk pool to provide for the integrity of the LCFS if credits are deemed invalid. As with any insurance policy, cost is a make-or-break factor. In this instance, the cost is the mechanism of seizing differential CI's resulting from actual efficiency gains generated by biofuel facilities and their inherent real market value. Under the proposal, the cost is borne by pathway holders and innovation is stifled because CARB would take the operational credits and disallow any retroactive credit recognition. Innovation is further dulled by the proposed substantiality provisions which we will discuss later in our comments.

If credits are deemed to be of sufficient validity to be used as a backstop for the LCFS program, then they should be considered of sufficient value to be awarded to the producer that earned them. The goal of the buffer account is to create a fund of credits to be used in an invalidation event that the market cannot backfill. This leaves the cost of invalidation risk in the market and simultaneously pulls any additional credits that may be generated out of the market. This is a double standard representing significant costs to fuel producers. (ACE1_41-2)

Comment: In 95488.4 (a), the amendment proposes that a pathway applicant can add a "conservative margin of safety" value to their Carbon Intensity (CI) to ensure that a project's natural variability does not cause it to operate above its certified CI. Fuel producers are required to maintain an operating CI beneath their certified CI to maintain compliance in the LCFS program, based on 24 months of production data. It is our understanding that any project greenhouse gas reductions that are verified above the margin of safety or operating CI value will generate credits that are placed into the Buffer Account. Any project that generates verified emissions reductions beyond their operating CI sacrifices those emissions to the Buffer Account.

…

However, DTEBE has concerns about how the margin of safety operates for RNG pathways. The margin of safety is used to increase a project CI and ensure that a project stays below its certified CI. While this system may be appropriate for fuel production that operates at a steady state with little CI variability, this system is problematic for dairy RNG projects. The CI of dairy RNG projects faces some amount of variability that is out of the project operator's control. A variety of factors can cause fluctuations in CI including temperature patterns, the efficiency of gas production, and the ratio of milking to non-milking cows. Forcing dairy RNG projects to maintain a healthy margin of safety to ensure LCFS compliance may result in sacrificing material project value for dairy RNG projects, especially in the initial project years when project variability is being fully determined by the project operator.

DTEBE recommends implementing a system to share this value with the project operator by splitting any verified emissions above the margin of safety or certified CI value equally between the project and the Buffer Account. Sharing these verified emissions reductions will provide a positive incentive for all projects in the LCFS program to set a solid margin of safety value as part of their ongoing participation in the LCFS program. The ability to recapture some of this project value will help ensure that project operators implement margin of safety values that generously capture project variability. Positively reinforcing the use of a healthy margin of safety value should reduce the number of projects that are out of compliance because of an unexpected increase in their verified CI. Sharing value will also reward continual improvement of project CI by helping projects to realize some of the improvement value generated when a project outperforms their certified CI faster than they would by adjusting their CI in subsequent operating years. (DTEBE1_56-3)

Comment: RPMG strongly opposes mandated injection of operational CI differentials of certified CI verification results into the Buffer Account. Operational CI credit should be awarded to the fuel producer first in all instances. Individual fuel producers should be allowed to pledge excess credits to the buffer pool if they so choose. Unclaimed credits may be deposited to the buffer account on a predefined schedule after allowing the stakeholder sufficient time to claim the verified CI differential. This would leave intact the ability to populate the buffer account as deemed necessary by CARB, while also retaining incentive for the generator to outperform their CI score whenever possible. There are examples of post period crediting today with non-metered electric utility providers that is analogous to providing verified credits to producers at the end of the verification engagement.

The buffer account concept as constructed and defined in § 95486(b) is both punitive and ineffective. Its concept is to provide an insurance risk pool against potentially invalidated credits. As with any insurance policy, it comes with a cost. In this instance that cost is the mechanism of scooping up differential CI's that are produced as a result of actual efficiency gains generated by biofuel facilities and their inherent real market value. The cost borne by pathway holders, whereby CARB pilfers these operational credits and disallows any retroactive credit recognition, is an innovation killer. When there is no incentive to get incrementally better, CI's will stagnate at a greater cost to the program. This dampening effect is amplified further with the rule's substantiality provisions.

If the credits are deemed to be valid enough to be used as a backstop for the program, then they should be considered valid enough to be given to the facility that produced them. It is true that previously if a facility produced a fuel below their certified CI score that those "additional" credits were not given to the facility, but it is also true that those additional credits were not certified by a third party and deemed worthy of regulatory consideration.

In any given reporting cycle, if a biofuel facility overachieves—potentially significantly—and can show an actual reduced CI, there is no immediate benefit. Rather, the regulation takes those credits and places them in the buffer account. But on the flip

side, if an entity is slightly over their certified CI score the enforcement implications are severe. Staff's recommendation for facilities to avoid any possibility of not achieving their CI score is to build in "head room". This headroom guarantees that credits will fund the buffer pool at a cost to liquid fuel producers. All that value is lost from day one. The cost of this lost opportunity is NOT equally borne by electricity generators as they again benefit from a special provision at § 95488.8(i)(1)(a).

The goal of the buffer account is to create a fund of credits to be used in an invalidation event that the market cannot backfill. The proposed construction leaves the cost of invalidation risk in the market AND simultaneously pulls any additional credits that may be generated out of the market. This is a form of double jeopardy that represents significant costs to fuel producers. Further, as currently proposed, this buffer account is not accessible to active fuel producers. It is only a back-stop for insolvent producers. Therefore, liquid fuel producers are funding this risk pool they cannot access themselves. (RPMG1_64-6)

Comment: CARB proposes that the producer may establish a margin of safety. Per 95488.4 "A fuel pathway applicant may add a conservative margin of safety, of a magnitude determined by the applicant, to increase the certified CI above the operational CI calculated based on the data submitted in the initial fuel pathway application, to account for potential process variability and diminish the risk of non-compliance with the certified CI."

AECA recommends that the program share the value generated when a producer verifies carbon reductions beyond the provisional or certified CI, which would incorporate the margin of safety. Without knowing that the project can capture part of this value, project owners will limit their use of the margin of safety, increasing the likelihood projects are out of compliance at the end of the year and putting the success of the program at risk.

In the first two years, corresponding to the period of the provisional CI, we suggest sharing any verified emissions reductions above the projects margin of safety and/or provisional CI level, with 75% of the additional verified emissions to the project owner and 25% to the Buffer Account. After the initial 2-year period, we recommend a 50/50 split of any verified emissions above the certified CI and/or margin of safety value on an ongoing basis.

In early years, project producers will have the least knowledge and as a result are at greatest risk. The provisional CI is initially based on three months of data, and dairy project performance over this three-month period may vary substantially from the average for the year. The provisional CI will likely be more conservative than the actual project CI during this initial period, placing a material amount of project value at risk.

It is worth noting that this variation will also disproportionately impact California dairy projects. Given California's warm climate, its dairy digester inventory is predominantly made up of covered lagoon digesters which operate at ambient temperatures and have wide production variances based on season. By contrast, the majority of digesters in

the rest of the country are plug flow and tank digesters, which have controlled temperatures and as a result will have less seasonal variation.

The 75/25 recommendation for sharing of the unused margin of safety/additional reductions in the first two years reflects the lack of initial experience by the industry and individual developers. It also takes into consideration the importance for projects to perform well financially from the start. Low initial returns may result in a project's failure to meet debt payments and/or equity hurdles. It will also likely impact returns to the farm partner, whose payments are often subsequent to debt and equity. The failure to provide returns will limit subsequent project development. Sharing the value of additional emissions reductions in the provisional period rewards owners who are improving their CI score and helps ensure the long term success and stability of dairy RNG projects.

After the initial 2-year period, with significant project specific experience, and corresponding with the provisional CI being replaced with the certified CI, we recommend a 50/50 split. This would provide a simple sharing of credits between the project owner and the important buffer mechanism.

A failure to meet the required CI limit could be severe both to the individual project and the broader industry efforts. (AECA1_72-5)

Comment: The verified operational carbon intensity ("CI") of the fuel may vary from the annual fuel pathway report. In the proposed changes to the regulation CARB is establishing a "buffer account" (LRT-CBTS) for credits and deficits. The regulation will penalize parties using overly aggressive carbon intensity values, but when parties use conservative carbon intensity values they are not rewarded for any improved performance. We request that any incremental CI benefit obtained during a reporting cycle be allowed to be claimed by the fuel producer. (LOVE1_73-1)

Comment: There are significant issues with the proposed buffer account. As proposed, the buffer account would be maintained by the Executive Officer who would manage LCFS credits generated by producers who have invested significantly in their operations to best the certified CI. The producers of these credits would not be able to take advantage of these credits. This sends the wrong message to producers who are significantly investing in low carbon fuel production. We view this generation of credits as a taking from the producer which sends a very bad policy signal to the low carbon fuel industry.

Biofuel pathway holders are the only entities subject to this provision since there is no CI verification requirement for the EV pathway using the California grid mix. In essence, biofuel pathway holders who diligently work to improve their operating CI score automatically lose out on any value generated between the lower operating CI and the certified CI. Instead the value is absorbed by ARB to protect the integrity of the LCFS program. While we certainly can understand and appreciate Staff's desire to identify a way to further protect the program's integrity, this is unfair to a producer, especially if

that producer is small or depends upon full credit generation to make the project pencil. (SCG1_75-9)

Comment: As many commenters have pointed out through the stakeholder process, low-carbon biofuel producers face a number of uncontrollable factors that may cause the actual (i.e., verified) CI of their fuel to be slightly different than the reported CI in the fuel pathway approved by CARB. For example, extreme weather conditions in a given growing season may impact feedstock yields and quality, or changing market conditions may cause feedstock and fuel transportation distances to deviate slightly from the values in the pathway. These sorts of changes may result in minor variations in the actual CI performance of the pathway. Due to these operational uncertainties, ethanol producers often use conservative operational values for the fuel pathway applications they submit to CARB for approval, leading to slight overestimation of CI performance and leaving a margin for slight variance in actual CI performance.

However, it is not uncommon for a plant's actual CI performance to be better (i.e., lower) than the reported pathway CI, meaning the ethanol pathway is generating more actual GHG reduction than is indicated by the certified pathway. This is typically due to more efficient operation of the biorefinery, but also may result from higher-than-expected feedstock yields and quality.

Unfortunately, CARB's proposal for addressing these slight discrepancies is inequitable and fails to incentivize more efficient practices that would drive actual CI performance below the certified pathway CI. CARB is proposing that if the actual verified CI is lower than the certified CI, the pathway holder can either: 1) retain the originally certified CI; or 2) request to replace the previously certified CI with the updated (verified) CI on a go-forward basis, assuming the improvement meets the substantiality requirements. In either case, the ethanol producer is forced to forgo the additional CI credit generated below the certified CI level, meaning actual GHG reductions are not being recognized.

On the other hand, if the actual verified CI is found to exceed the previously certified CI, the fuel pathway holder is deemed "out of compliance" and "may be subject to credit adjustment and possible enforcement investigations." Thus, ethanol producers are not rewarded for actual CI performance that is lower than the certified CI, but face enforcement penalties if the actual CI performance is higher than the certified CI.

We strongly recommend that credit "buffer accounts" be adopted in a way that allows producers to generate and store CI credits when actual verified CI performance is lower than the certified pathway CI. These credits would then be available to the producer to offset potential credit invalidation in the event that a future verification audit finds that the producer's actual CI performance is above the certified CI.

As a matter of general fairness, we encourage CARB to implement buffer accounts in a manner that truly serves as a "buffer" for credit generators, allowing surplus credit to be generated when verified CI performance is lower than the reported CI. (RFA1_80-19)

Comment: Clean Energy supports the effort of Staff to improve liquidity in the LCFS market by minimizing buyer liability through the establishment of a buffer account. However, we encourage Staff to reconsider the source of credits deposited into the buffer account. We agree that stranded credits from deactivated LRT-CBTS accounts, as well as a percentage of credits from carbon capture and sequestration projects (using a project risk rating framework) are appropriate sources of buffer account credits, especially the latter considering the perpetual risk of loss associated with carbon capture and sequestration projects. However, actual, verified GHG reductions achieved by active biofuel producers in the LCFS should not be deposited into the buffer account.

Under the proposed verification program, a producer's credit generating ability is capped at either the certified CI or the operating CI, whichever is higher. If a producer's operating CI is higher than the certified CI, the producer will have to forfeit the quantity of credits that were over-generated. Conversely, if the operating CI is lower than the certified CI the producer cannot recognize that incremental GHG reduction and economic value as these “stranded” credits will be deposited into the buffer account. We believe the credit value should remain with the producer not only because by doing so encourages a producer to become more efficient, it also is just as the producer is the entity taking on the risk. The operating CI represents an accurate and actual GHG reduction achieved by the producer from delivering its fuel to the transportation fuel market. Producers who work diligently to lower their CI score should be allowed to recognize the full benefit of this reduction instead of having this value diverted into the buffer account, especially considering that the producer is subject to ongoing verification costs to validate its annual operating CI.

Considering the proposed verification program limits buyer liability on credits generated by biofuel producers, we believe that biofuel producers with verified credit generation should not have any “stranded” credits deposited into the buffer account. Instead, Clean Energy recommends that Staff develop a “true up” strategy that allows biofuel producers to recognize the actual GHG reduction benefit of their operations, as based on the operating CI. (CE1_92-4)

Comment: Along the same lines I also want to touch on the proposed buffer account, which is also a mechanism to provide additional integrity to the LCFS program in the instance of invalidating credits are not recoverable. One of the proposed sources of credits to be deposited into the buffer account are what's termed as stranded credits from biofuel producers. These are essentially credits that as proposed cannot be achieved or recognized by biofuel producers if their operating carbon intensity score is lower than the certified carbon intensity score.

So really we see this as additional value that producers are bringing to the State of California for reducing carbon intensity on transportation fuel space. And we believe that that's value that should be achieved and recognized by the producer and not deposited into the buffer account.

So we urge staff to reconsider depositing that additional value into the buffer account because it becomes -- we want to incentivize producers to reduce the carbon intensity

of their operations. So if we can revisit that issue, maybe come up with a true-up mechanism for the actual carbon emissions that have been reduced, that would be much appreciated. (CE2_T5-4)

Comment: I'd also like to echo a couple of previous concerns, one with a buffer account. We do believe actual verified greenhouse gas emission reductions achieved by biofuel producers should not be deposited into the buffer account. (CE3_T31-3)

Comment: Kern has concerns with the inclusion of paragraph (A) in this section, which would grant the Executive Officer the authority to place in the buffer account any credits that could have been claimed were it not for the proposed denial of retroactivity in section 95486(a)(2). Kern urges ARB to amend this paragraph referencing retroactive credits as an allowable source for credits in the buffer account, consistent with Kern's suggested edits to the provisions for retroactivity noted in the comments specific to Section 95486(a)(2) above. (KERN1_115-4a)

Comment: We also recommend that in *§95486, Generating and Calculating Credits and Deficits*, CARB incent entities to opt-in to the LCFS program by allocating credits to a generator as opposed to moving credits to a buffer account in instances where an entity verifies that they had a lower CI than the CI listed in the annual Fuel Pathway Report. (PGE1_120-14)

Comment: (3) *Proposed "margin of safety" and consequences of exceeding certified carbon intensity ("CI"') values.* To encourage the reporting of actual verified emission reductions under the LCFS program, we believe the "margin of safety" concept should be replaced with creation of an individual buffer subaccount, which could be populated not only as described in the previous paragraph but also proactively by the producer to set aside credits that would be retired to make the system whole if credits were over-generated due to CI variability in a compliance year.

…

Section 95488.4(a) provides that a "fuel pathway applicant may add a conservative margin of safety" to its certified CI value to "account for potential process variability and diminish the risk of non-compliance with the certified CI". A certified CI that represents anything other than the actual lifecycle fuel pathway emissions of the fuel delivered to California undermines the goals of the program and results in the forfeiture of economic value associated with the production and use of a low carbon fuel.

As the Proposed Regulation reads today, if the reported CI of a pathway for a compliance year is lower than the verified operational CI, the credits associated with that difference are deposited into a general buffer account. On the flip side, if the reported CI of a pathway for a compliance year is higher than the verified operational CI, the producer is out of compliance with the LCFS regulation and subjected to possible enforcement action under Section 95488.10(a)(7). Because the enforcement powers granted to CARB staff under the LCFS are largely unlimited in scope, we believe that absent any aggravating factors, enforcement should be a means of last

resort to make the system whole if a producer over-generates credits in this instance. As an alternative to enforcement, credits from the individual buffer subaccount would be retired to address any over-generation. If a shortfall exists, the producer would have the obligation to procure the additional credits necessary to comprise the invalidated amount. Unless aggravating factors exist, these remedies would apply prior to being deemed out of compliance with the LCFS regulation and subjected to possible enforcement action. (EMRE1_B16-3)

Comment: Also, I encourage you to allow the fuel producers to keep some or all of their buffer accounts because it's -- in LCA speak, you're supporting continuous improvement. And if they track their carbon intensity, as we've been encouraging them to do, and they track it every month, and they see it go down every year, they ought to be able to keep a fraction of that, which provides them further incentive to make very small changes in efficiency and improvements that will help bring down carbon intensity in the future. (LCA5_T38-4)

> **Agency Response:** The commenters express concern that the proposed buffer account would reduce the number of credits a reporting entity could generate for reporting fuels using fuel pathways with certified carbon intensity (CI) values. Staff proposed that the buffer account would be populated by the following four sources of credits: (1) credits representing GHG emission reductions that were not validly claimed because of the retroactive crediting prohibition in the LCFS rule as referred in section 95486(a)(2); (2) credits for GHG emission reduction representing the difference between the certified CI, that was used for quarterly reporting, and the operational CI verified at the end of each year; (3) credits remaining in a deactivated account that can no longer be claimed by any entity; (4) and lastly, a percentage of credits from CCS projects determined using the risk rating framework provided in the CCS protocol. Staff would like to clarify that the credits representing all of the categories above are not available to the fuel reporting entities under the historic rules. Therefore, adding these credits to the buffer account does not affect or reduce the number of credits generated by the fuel reporting entities.
>
> A fuel pathway applicant may choose to add a conservative margin of safety, of a magnitude determined by the applicant, to request a certified CI value higher than the operational CI calculated based on the data submitted in the initial fuel pathway application, to account for potential process variability and minimize the risk of non-compliance with the certified CI. Staff did not propose to issue credits for the difference if the verified operational CI is lower than the certified CI as that would result in significant accounting complexities for the program balance of numerous credit generators which could create uncertainty in the credit market. Staff believes if the verified operational CI is lower than the certified CI then an option to reward the CI difference would be to issue credits post verification. This would ensure the credits are generated based on accurate verified data and credit balances are not subject to retroactive adjustments.

Staff also proposed if the verified operational CI is lower than the certified CI the fuel pathway holder could request to revise the CI going forward. Staff believes this option provides the fuel producers necessary incentive to reduce the fuel CI by continuously improving the fuel production process.

In response to the commenter's recommendation for creating individual buffer accounts in EMRE1_B16-3, please see Response H-2, Individual Buffer Account Provisions, in this chapter.

H-4. *Buffer Account Contribution from CCS Projects*

Comment: We understand CARB's need to set Buffer Account contributions conservatively at first, before a broad experience with CCS projects is in place. At the same time, in order to deploy successful CCS projects, potential investors need to be able to reasonably predict project returns. Table G1 in Appendix G is a good start to helping industry understand how projects returns will be affected by Buffer Account contributions.

However, not all projects will be able to fit into predefined risk categories absolutely. For example, under the "Financial" risk type, Table G.1 suggests that project participants are of low risk if they have "A" credit ratings. However, credit ratings are only acquired by entities that have debt. Since CCS deployment is still in its early stages, potential early projects could be funded purely through private equity. These newly formed private equity firms could be more financially stable then an A rated company simply because they have access to large funds. Projects that are well-funded by private equity should not be relegated to a higher risk profile simply because they have no need to borrow funds for a project. <u>We suggest, therefore, that the Executive Officer have the ability to review cases in which a credit rating is not available and determine the appropriate risk level with the project entity.</u>

Under the "Well Integrity" risk type, CARB has predefined Low Risk and High Risk by segregating them as Class II and Class VI respectively. Though a well may be permitted under Class II, it may have been designed and constructed to standards beyond the minimum requirements of a Class II well. In fact, some operators have disclosed that they exceed Class II requirements of their own accord.[28] <u>The Executive Officer should examine the actual well integrity risk for a project's wells as opposed to relying on their regulatory class under USEPA (UIC) only, and assign a risk rating accordingly.</u> It is not clear whether the intent of Table G.1 under this risk type is to examine the actual regulatory classification under USEPA (UIC) only, or the actual standard of the wells.

[28] See Mordick, B., Peridas, G., 2017, Ch.5.

In addition, other risk categories may not fall into the predefined risk profiles setup in Table G.1. <u>We recommend that the Executive Officer have the option to modify or update the risk rating contribution up or down within the bounds set in Table G.1 for a project based on information on technology and practices provided by the prospective project operator.</u>

In addition to these concerns relating to the Table G1 contained in Appendix G that effectively establishes a minimum risk floor rating for all projects, we think there are additional opportunities to clarify the methodology of risk assessment and utilize the credits that CCS projects have deposited into the buffer account to lessen the burden of unnecessary long-term financial exposure the protocol now creates. Specifically, we advocate three additions to the rule:

1. The utilization of the risk calculation methodology contained in Appendix G not just to determine the amount of mandatory credit contributions to the buffer pool but also to assign the level of financial responsibility instruments that are required by C.7.(a)(3).
2. The establishment of a new table in Appendix G that contains a different risk matrix for the post-injection phase of projects. We think that by this stage in a project's lifespan, most projects will have a sufficient history to establish the risk of atmospheric leakage with far greater accuracy and certainty, and that the table should contain appropriate risk values that enable this for qualifying projects.
3. Since a project will have contributed a substantial number of credits to the buffer pool during its lifespan, we think that the project's specific contributions should be available to use as a financial responsibility instrument to cover future leakage risk. (CCSPD1_106-28)

   Agency Response: Staff understands the commenter's suggestions for changes to the buffer account contribution from Carbon Capture and Sequestration (CCS) projects. Staff proposed the *Table G.1. CCS project contribution to CCS project risk rating based on risk types* to provide a clear methodology for quantifying risks associated with a CCS project and to determine the credit contribution to the buffer account. This would allow a project developer to estimate buffer account contribution in advance while reducing the uncertainty associated with individual project risk assessment. This would also provide an opportunity to project developers to identify the risk types for which the mitigating action would deliver the maximum risk reduction for the overall project. Further, staff proposed to rely on established standards and certifications that are widely accepted. This avoids the need for additional assessment by CARB staff, not only preventing extra administrative work for staff but also accelerating the project application review process.

   Staff would like to clarify, when a project operator is unable to demonstrate the required ratings to qualify for low and medium financial risk, its financial risk would be considered high.

   For the purpose of the buffer account contribution, staff believes it is appropriate to generalize a well's risk by looking at whether or not the well has a Class VI permit. This is not a minimum requirement of the Protocol, but an optional requirement to incentivize actions that would reduce the overall risk of CCS projects. Staff will continue to work with stakeholders to examine additional

voluntary mechanisms to be used as part of the buffer account, to meet the goals of simplifying implementation and incentivizing reductions in overall risk.

Staff does not agree that the buffer account is an appropriate mechanism for the determination of financial responsibility during the post-injection project phase. The methodology laid out in the CCS Protocol is more appropriate for that determination.

During the post-injection period, a CCS project no longer generates credits (CO_2 is no longer injected), and thus, it is unnecessary to develop a risk rating for buffer account contributions during that period.

Staff does not agree that the buffer account is an appropriate tool to replace the financial responsibility provision. Although the updated CCS Protocol uses the buffer account mechanism to ameliorate market risk in the case CO_2 leakage occurs beyond 50 years post-injection, the buffer account for CCS projects exists primarily to ensure that the LCFS market remains whole in the case where market actors are unable to reimburse the market for leakage that occurs. The financial responsibility provisions exist primarily for making sure that CCS projects have enough capital available to repair the physical environment in the case of leakage.

The proposed risk rating framework is based on staff's best knowledge of the risk factors associated with the CCS projects. As implementation proceeds, and more information becomes available, staff may consider updating the risk rating framework, as appropriate.

I. Infrastructure Crediting

I-1. Multiple Comments: *Support for the Proposal on Hydrogen Infrastructure Capacity Credits and Infrastructure Credits for DC Fast Chargers*

Comment: An important aspect of the LCFS is that it provides support for hydrogen fueling infrastructure. Hydrogen as a transportation fuel provides a low carbon, clean air, and zero emission vehicle fuel for of the State while supporting Executive Order B-48-18. Enabling significant cost reduction through station development at sustained pace and scale should be a key component of the program moving forward. We support the efforts to achieve these goals and stand ready, as a both a transportation fuel and infrastructure provider, to work toward accomplishing the State's low carbon goals. (LOVE1_73-6)

Comment: We also strongly encourage your adoption of the *Hydrogen Infrastructure Pathway* to generate credits under the Low Carbon Fuel Standard (LCFS).

We also would like to highlight that one of the key policy recommendations of a soon to be released White Paper on Renewable Hydrogen (RH2) identifies that LCFS credits are a vital market incentive, establishing a critical revenue driver for fuel producers while the market for FCEVs is in its infancy.

…

EIN recommends extending the LCFS Program to provide Hydrogen fuel infrastructure developers long-term certainty in order to make capital investments in our nascent industry.

Extending the LCFS credit market for 10 years or longer would provide a significant level of stability and bankability for investors as a support mechanism for a hydrogen market that could take decades to mature. Developers of hydrogen stations and production facilities could model revenue from LCFS credits through a significant portion of the lifetime of their equipment rather than just a few short years, reducing investment risk and making projects more attractive. This would also incentivize production of renewable hydrogen while lowering prices to consumers because LCFS credit values increase along with the amount of renewable content in the fuel. (EIN1_B11-2)

Comment: …and wants to also encourage your adoption of the hydrogen infrastructure pathway that you'll hear more about shortly. (EIN2_T30-2)

Comment: The California Energy Commission is funding the initial hydrogen refueling network for the State. Currently California has 34 open retail stations and another 30 in planning or under construction, for a total of 64 funded stations.

We are always open to ideas about how best to incentivize and accelerate hydrogen and would be supportive if the Board directs the staff to look into this.

We are confident the Energy Commission program can get California to 200 stations if the Governor's budget is approved as proposed, but definitely need additional tools to help the hydrogen network achieve commercial scale.

This could incentivize the companies involved to use more renewable hydrogen than ever before, contributing to the reduction of greenhouse gas, criteria air pollutant, and toxic air contaminant emissions through the increased use of renewable hydrogen. (CEC1_T35-1)

Comment: Emanuel Wagner, our deputy director, and I are here today to voice our strong support from the business council for the proposal on hydrogen infrastructure capacity credits, which was put in the docket last November. A small group of stakeholders from the industry is here today to outline the proposal in a bit more detail.

…

And once again, the CHBC strongly supports the proposed capacity credit program on behalf of our members. (CHBC1_T37-1)

Comment: Our proposal, as submitted in November of 2017, urges the creation of a hydrogen infrastructure pathway to generate LCFS credits based on the installed fuel dispensing capacity of our hydrogen stations.

Before I start I'd like to express my sincere thanks to the ARB Board and staff members who helped us put together with feedback and inputs a proposal that supports California's low-carbon, clean-air, zero-emission-vehicle goals.

If adopted, this proposal would generate LCFS credits along two routes. The first is, credits would be generated directly through hydrogen sales as per current policy.

And secondly, the remaining installed capacity -- unused capacity of the refueling stations would generate credits.

In both cases, the credits generated would be calculated based on the carbon intensity of the supplied hydrogen.

Creating this pathway would meet the following goals:

It would expand the availability of best-in-class low-carbon hydrogen fuel;

It would accelerate zero-emission vehicle adoption by expanding the infrastructure; and

It would decrease the carbon intensity of hydrogen fuel by providing incentives to station operators to select renewable source pathways.

Our proposal is constrained in a few ways:

In particular, it has a limited time of 10 years to fixed sunset.

Secondly, we have a maximum capacity fraction that would decrease from 100 percent to 40 percent over the lifetime of the program to build in the incentive to sell hydrogen and not rely exclusively upon these credits.

Thirdly, we would cap the program at 500 stations, and to stations that are 1200 kilograms per day or smaller.

Fourthly, we would require a minimum of 40 percent renewable content in the fuel, which exceeds our current requirements in the State.

And there are various other constraints to designed to work together with the existing ARFVTP programs.

As a representative of Air Liquide, a producer-distributor of hydrogen, and also an owner and operator of several hydrogen refueling stations in California, from our perspective these credits would encourage private investment in more renewable hydrogen production. It would enable growth, and growth is what sets us in a direction toward fuel-cost reductions.

In addition to the continued build-out of stations in California, a successful hydrogen market will require significant private investment in renewable hydrogen production facilities and distribution infrastructure. We estimate for every dollar that is being invested in refueling stations, matching dollars, one or more, will be required to expand hydrogen production facilities, distribution centers, and production in the State.

Such investments will include renewable hydrogen production from electrolysis and biogas reforming, as well as refrigeration, liquefaction, compression, and dispensing with electricity from solar, wind, and other renewable sources. Private investment of this magnitude requires stable, predictable markets supported by policies similar to this one, of which we're supportive. (CHBC1_T37-2)

Comment: My name is Michael Lord representing Toyota Motor North America. We have contributed to the development of this proposal and are strongly supportive.

Toyota believes that no advanced environmental technology can truly succeed unless it becomes a mainstream mass-market technology.

To achieve this we are working on a broad portfolio of advanced technology vehicles including fuel cell, battery, plug-in hybrid, and hybrid electric vehicles.

Toyota has learned from nearly 20 years of marketing advanced technology vehicles that achieving large-scale volumes requires a deliberate focus on growing the market. This includes flexibility in the regulation, continued vehicle incentives, and a process of continuous improvement of infrastructure build-out policies.

Toyota believes that fuel cell vehicles have a great potential for electrifying the full spectrum of vehicles from passenger cars to Class 8 heavy-duty trucks.

In addition to the over 3,400 Toyota Mirai on California's roads, fuel cells power our big rig Class 8 heavy-duty demonstration truck being tested in the ports of Los Angeles and Long Beach.

Fuel cell vehicles like the Mirai are on the road, but it's clear that the availability of hydrogen fuel, both the number and capacity of the fueling stations, is a limiting factor for customer adoption.

In fact, we're hearing this directly from our current and potential customers. They love the Mirai. It's smooth, quiet, comfortable, and zero emissions. But the lack of station and station capacity is a real concern.

To this end, we support -- strongly support Governor Brown's 2.5 billion dollar ZEV incentive, including the commitment to bring 200 stations to California by 2025 proposed in Executive Order B-48-18.

We also agree with the recommendation in the executive order that states that all State entities recommend ways to expand zero-emission vehicle infrastructure through the Low Carbon Fuel Standard.

The LCFS capacity credit proposal outlined today is aligned with the intent of this recommendation and will go a long way to get more infrastructure built. This proposal will allow for cost reductions through economy of scales, resulting in fuel prices reaching gasoline parity or better.

The proposal will also incentivize lower carbon hydrogen and will have minimal impact on the overall LCFS policy.

Therefore, we kindly ask for support of the LCFS capacity credit proposal so we can bring the right kind of hydrogen stations to the drivers of California. (CHBC1_T37-3)

Comment: Good afternoon. I'm Robert Bienenfeld, Assistant Vice President of Environment and Energy Strategy for American Honda. And we were involved in the development of the hydrogen path -- capacity pathway credit proposal and we support it.

We believe hydrogen can play a valuable role in achieving the State's 2030 and 2050 greenhouse gas and air quality goals. Along with the plug-in hybrid and battery electric vehicles, fuel cell vehicles have many important unique attributes that will help us reach the broadest number of potential customers in California.

Hydrogen is unique due primarily to the need for an entirely new refueling infrastructure. And unlike the electric infrastructure, which is supported by the PUC and large electric utilities, hydrogen has no natural way of rate-basing the growth of this essential energy carrier.

This proposal addresses the difference in an appropriate way, providing a specific incentive based on refueling capacity, for a defined period of time, limited in scale, and

helps us overcome the chicken-and-egg problem that is associated with alternative fuels but really is unique to hydrogen among the zero-emission fuels.

As stated previously, increasing the supply of hydrogen refueling stations is critical barrier to the widespread adoption of fuel cell vehicles. Today we have customers waiting in line for fuel, and we need to address this. And robust policy support will help.

This proposal will help us provide more coverage, that is, to say more areas of the State with hydrogen availability, and more capacity, that is, say more pumps and fueling positions for more customers and vehicles.

The proposal helps assure that infrastructure providers can ramp up fuel sales in a reasonable way without being severely constrained by operational costs.

Meeting 2030 and 2050 goals will require widespread adoption of zero- and near-zero-emission vehicles. Hydrogen fuel cell vehicles are needed for the range, refueling time, vehicle size, and climate toughness that no other zero-emission vehicle can provide.

On behalf of Honda, thank you for the opportunity to present our perspective and support this proposal. (CHBC1_T37-4)

Comment: I'm a founder and chief development officer of First Element Fuel. We've contributed to this proposal and we strongly support it.

First I want to thank the members of the Board and CARB staff for pushing the world towards cleaner vehicles. I can assure you that my company wouldn't exist today if it weren't for you guys and it weren't for the Energy Commission and all the great work you've done together on ZEVs. So big thank you.

My company was founded here in California a little over four years ago for the sole purpose of retailing hydrogen to fuel cell vehicle customers. And we have a strong focus on a positive customer experience because we think that's critical to driving the adoption of ZEVs.

With 19 hydrogen stations here in California, we own and operate the majority of the 34 stations open in California today. And from our on-the-ground experience, I can tell that the big challenge we face from an economic view is that, one, we need to open stations ahead of the cars so that we're not seeing the lines that Robert's talking about; and that, two, we need to put a full set of resources on operating those stations to assure a positive customer experience. That's especially important during these early years, but it's also during these early years that the stations are under-utilized.

Today, if that one customer shows up, whether it be one out of ten customers that day or one out of a thousand customers that day, it doesn't make a difference to them. We need that one customer to have a positive experience as part of their day-to-day ZEV driving, and we put resources on our station to make sure that happens.

But that's a big cost to us in these early years when the market is embryotic. So the revenue stream provided by this program, if adopted, will be a huge factor in helping station developers like First Element manage these early stage economic challenges. Because in the end what we're trying to do is transition our industry from today's embryotic stage to early commercial scale so that we can keep pace with and not stifle the rollout of fuel cell vehicle deployments.

This proposal would work in conjunction with other existing policies, like the Energy Commission's Hydrogen Station Funding program, the CVRP program, and the ZEV mandate, to achieve exactly that.

So, for the first block of stations that my company built two years ago, the infrastructure investment per vehicle was about five times the cost of that of the infrastructure for a plug-in vehicle.

For the stations we're currently building we've brought that cost down to just two times that of the cost for a plug-in vehicle.

This proposal together with the CEC's funding program will help us continue to drive the cost out of the infrastructure as we increase in scale.

So in 10 years time, I can tell you that First Element is very confident that there is an off ramp for government support and that we'll be able to compete head to head with gasoline on a cost-per-mile basis.

So this proposal, if adopted, will give us a powerful tool to get over this early hump, achieve the commercial -- achieve the early commercial scale, and get to that stage. (CHBC1_T37-5)

Comment: We have also contributed to the development of this proposal and are strongly supportive. I'd like to echo the comments of my peers who have gone before me and support those yet to come.

This proposal will allow hydrogen fuel to transition to full commercialization. This would also continue the leadership of California in advancing hydrogen for transport and in acting as the global focal point for investments and activities.

But more importantly, it will provide the basis for private investments to scale up equipment manufacturing volumes, unlocking substantial cost reductions on equipment for companies such as my own.

And specifically for now the efforts already made in California on hydrogen have motivated us to establish a business presence and make investments in the State.

This LCFS proposal for hydrogen will greatly expand opportunities to continue our own investments in California. (CHBC1_T37-6)

Comment: The expansion of the LCFS program through this hydrogen infrastructure pathway that my company was involved in developing, along with the others, provides the necessary incentive for companies like United Hydrogen and others to enter the California market.

We believe this proposal will increase the -- and diversify supply of hydrogen in the State, low carbon intensity hydrogen fuel for California, while at the same time lowering the cost of fuel for producers and consumers. And with the implementation of this proposal that we have before you today, it would increase the adoption of fuel cell vehicles among the consumers in the State as well as accelerating the State meeting their air quality and greenhouse gas goals. (CHBC1_T37-7)

Comment: We were also involved in developing this proposal and we're strongly supportive of the hydrogen infrastructure pathway.

We believe this proposal will create an effective and appropriate incentive supporting both the expansion of the hydrogen fueling network and the reduction in the carbon intensity of hydrogen fuel. This supports the low-carbon, clean-air, and zero-emission vehicle goals of the State.

From our analysis the proposal partially offsets the unique low initial utilization of the hydrogen infrastructure, thereby de-risking private investment. And we think it accelerates existing incentives in the LCFS program to develop low-carbon hydrogen production.

While we believe the proposal is effective in de-risking and decarbonizing hydrogen, it is also appropriately constrained by eligibility criteria to prevent unintended actions, and by sunset provisions and caps on the number and size of stations, such that the overall impact to the LCFS credit program is unlikely to exceed 1 to 2 percent of total credit generation.

The development of this proposal began with an opportunity and broadly shared objective to increase the scale and reduce the cost for hydrogen infrastructure, and thereby enable adoption of zero-emission fuel cell vehicles.

This scale will require major investment from the private sector and make significant contribution to the State's air quality and greenhouse gas reduction goals. For example, we have completed and published work showing the capital and operating cost of hydrogen refueling stations can be reduced by more than 50 percent immediately if there's a modest increase in hydrogen scale, a scale that is aligned with the Governor's executive order.

We support the hydrogen infrastructure pathway proposal as an effective, appropriate, and constrained approach to supporting expansion of the hydrogen fueling network and reduction in hydrogen carbon intensity, consistent with the LCFS policy and the Governor's executive order.

We think the result will be improved availability of best-in-class zero-emission vehicle fuel to support the efficient decarbonization of fuels and the widespread customer adoption of zero-emission vehicles, and enabling a positive cycle of cost reduction for progress toward the viable market conditions for hydrogen. (CHBC2_T37-8)

Comment: We do support the capacity credit proposal, both for hydrogen fuel cell vehicles, the hydrogen stations and for DC fast-charging. The truth is that infrastructure is a huge barrier for all types of electrification, whether it be fuel cell or plug-in electrics. And there's just simply not enough infrastructure for either one.

DC fast-charging makes that -- these vehicles available to a much broader spectrum of people, and we would appreciate those capacity credits. (UTILITIES1_T47-3)

Comment: The first is hydrogen infrastructure. As noted in the extensive earlier comments, hydrogen faces some unique challenges, particularly in the early market. And I won't rehash all those now, but I'll just say that we agree that with the right safeguards in place, and the right incentives in place, capacity-based credits could be an elegant solution to some of these early market challenges.

It could help create a stable environment, help drive private investment, and lower carbon hydrogen and help the industry scale up and reduce cost.

Given the essential role of hydrogen, particularly for larger vehicles in more difficult use cases, creative policy approaches are really needed to scale things up. (GM1_T49-1)

Comment: In the medium term we are facing a formidable goal established by Governor Brown for five million EVs in California by 2030. The proposed hydrogen infrastructure pathway to help build out a critical mass of hydrogen fuel stations supports this goal. Customers who must travel longer distances or who simply have range anxiety may be won over to ZEVs powered with hydrogen. It also holds significant promise for fueling heavy-duty vehicles. We appreciate the support of the Board for this pathway, and working with staff to develop it. (SHELL1_T50-3)

Comment: 14. Although not currently in the regulation, CalETC is supportive of a 15-day change allowing “capacity” credits for publicly-accessible hydrogen and DC fast chargers to help make fuel cell and battery electric vehicles more accessible to all Californians.

…

14. *Although not currently in the regulation, CalETC is supportive of a 15-day change allowing “capacity” credits for publicly-accessible hydrogen and DC fast chargers to help make fuel cell and battery electric vehicles more accessible to all Californians.*

CalETC supports capacity credits, provided there is a sunset for this program element and the fuel distributed at eligible stations is subtracted from the capacity credit value to prevent double counting. Both publicly-accessible DC fast charging and hydrogen fueling are not profitable investments at this early phase of the market. Both make

zero-emission vehicles more accessible to California residents who do not have access to home charging or a nearby hydrogen station. Increasing the number of DC fast chargers and H2 stations will help accelerate the market for both fuel cell and battery-electric technologies. A limited-time opportunity for these stations to generate LCFS capacity credits could help spur investment and ensure the stations are fully utilized in the future. CalETC supports a 15-day change to include capacity credits for hydrogen stations and DC fast chargers and will work with staff on the specifics of the regulatory modifications. (CALETC1_96-17)

Comment: The H2 coalition is advocating for LCFS credits based on the capacity of a H2 fueling station, rather that credits for only the H2 sold at the station. Capacity credits would sunset by a date certain and the credits generated from the sale of H2 would be subtracted from the capacity credit total. With the sunset and the subtraction, CalETC is considering supporting capacity credits for DCFC stations. (CALETC2_130-7)

> **Agency Response:** Staff acknowledges the support for the stakeholder proposal on hydrogen infrastructure capacity credits, submitted during the 45-day comment period, and for the potential to generate infrastructure credits for DC Fast Chargers.
>
> Staff agrees that the lack of refueling infrastructure is a barrier to ZEV implementation, and that the capacity crediting provisions would aid in the buildout of the necessary infrastructure to support the goals of Executive Order B-48-18. The final hydrogen capacity crediting provision proposed by staff is similar to the version submitted during the 45-day comment period, and to which the commenters refer. Staff's proposal by design is likely to contribute to cost reductions for both ZEV infrastructure and hydrogen fuel across the State, as well as greater adoption of fuel cell vehicles.
>
> Staff agrees that appropriate safeguards for this provision are necessary for correctly incentivizing ZEV infrastructure with LCFS credits. Staff would like to highlight several of these safeguards. Most notably, please see Response I-8.2 in this chapter regarding staff's decision to cap total HRI credit generation at 2.5 percent of the prior quarter's deficits, rather than capping the total stations that can receive HRI credits. See also staff's rationale for establishing a 15-year crediting period for HRI credit generation in Response I-6.6 in this chapter, as well as Response I-6.7 in this chapter for staff's rationale for allowing generation of up to 100 percent of station capacity. Please see also Response I-5.1, Carbon Intensity and Renewable Content Requirement for HRI Crediting, in this chapter regarding staff's requirements for the maximum CI and minimum renewable content percentage.
>
> In addition to crediting hydrogen station capacity, staff also included a provision to credit DC Fast Charging capacity for electric vehicles. Staff agrees that supporting infrastructure development in both industries would help to solve the chicken-and-egg problem facing zero emission vehicles today. Staff recognizes that both zero emission technologies have varying strengths and challenges, and

maintains that widespread adoption of both is necessary for reducing GHG emissions from the transportation sector. Commenters are correct in noting that infrastructure crediting could occur simultaneously with other government programs, subject of course to the exceptions listed in section 95486.2(a)(1)(C). Given the existing support available for ZEV infrastructure from other programs, staff expects, and has heard from industry, that the value of the LCFS credits will enable station/charger owners to ensure a positive customer experience. In addition, infrastructure credit generation is inversely proportional to throughput at each station/charger, meaning that the infrastructure crediting programs would self-sunset as throughput through each station/charger increases over time.

I-2. Multiple Comments: *Not in Support of Stakeholder Proposal on Hydrogen Infrastructure Capacity Credits and Infrastructure Credits for DC Fast Chargers*

Comment: CARB Needs to Maintain a Level-Playing Field Instead of Picking Favorites

One of the primary reasons California adopted the Global Warming Solutions Act of 2006 (AB 32) and CARB implemented the resulting LCFS regulation was the fact the production and use of traditional fossil fuels contributed to the lion's share of the state's GHG emissions. It was understood petroleum refiners would not take steps on their own to reduce the GHG emissions of motor fuel. Therefore, the LCFS was designed as a performance-based and fuel neutral mechanism to decrease the CI of California's transportation fuel and provide "an increasing range of low carbon renewable alternatives to conventional petroleum-derived fuels."

We encourage CARB to adhere to the letter and spirit of the LCFS by maintaining a level-playing field for a range of low carbon fuel alternatives instead of using the regulation to pick favorites. We are concerned the proposal violates the performance-based and fuel neutrality pillars of the LCFS by giving preferential treatment to "promote zero emission vehicle infrastructure and renewable electricity to ZEVs." The proposal to encourage the expansion of ZEV infrastructure also appears to be a departure from precedent. To our knowledge, LCFS regulations have never encouraged the expansion of biofuel infrastructure such as blender pumps which can dispense a wide range of ethanol-gasoline blends. Why would CARB use the LCFS to promote just one form of low carbon fuel infrastructure?

ACE supports the increased consumption of electricity in ZEVs and recognizes low carbon and renewable power generation can and should play an increasing role in helping accomplish the goals of the LCFS. We understand there is no silver bullet to reduce GHG emissions from the transportation sector, whether in California or across the world. Rather, low carbon sources of liquid transportation fuel such as ethanol and biodiesel and electric applications will together play a role in helping the LCFS and other clean fuel programs succeed. However, we oppose special treatment for any select fuel, including electricity and hydrogen pathways under the proposed LCFS regulation. (ACE1_41-3)

Comment: While we recognize the importance of hydrogen as a low carbon and zero emissions fuel, we do not support the stakeholder proposal to provide credits based on infrastructure capacity rather than fuel sold.

…

While we recognize the importance of hydrogen as a low carbon and zero emissions fuel, and the need for hydrogen fueling infrastructure, we do not support the proposal from Shell and other stakeholders to provide LCFS credits based on infrastructure capacity rather than fuel sold. The proposal is inconsistent with the fuel-neutral performance basis of the LCFS, and would set a precedent that could undermine the program over time. (UCS1_53-6)

Comment: *NextGen Opposes Capacity Based Infrastructure Credits*

Several stakeholders have requested that CARB institute a new protocol for awarding LCFS credits for the capacity of installed fueling infrastructure, rather than solely for the quantity of fuel dispensed, as is the practice under the current program. This concept is most often discussed in regards to hydrogen fueling stations, however stakeholders have also proposed extending it to electric or natural gas vehicle fueling equipment as well.

NextGen California opposes the creation of capacity-based LCFS credit generation pathways. We see this as an abrupt departure from the established, and quite successful, structure of the existing program. Fueling infrastructure providers already have ample incentive to install commercial and/or public fueling facilities: they are eligible to claim the LCFS credits from fueling activity at their stations. Adding a new pathway breaks the fundamental relationship upon which the LCFS is based: that credits are awarded for activities which actually reduce emissions. Creating this new credit pathway would establish a troubling precedent that the program will assign credits, which have real financial value, based on uncertain expectations of future emission reductions. Doing so would essentially move the risk that a project will fail to live up to its projections onto California residents; if a given piece of fueling infrastructure which was supported by capacity-based credits did not produce the expected emissions cuts then California the LCFS would not yield the actual reductions implied by the program's credit transactions and the state would be off track to hit its SB 32 goals, other programs Would have to make up the shortfall. The resulting costs would be passed on to consumers. (NEXTGEN1_124-32)

> **Agency Response:** Please see Response I-3.1 in this chapter. Staff acknowledges that ZEV infrastructure crediting is a departure from the historical mechanism of generating credits based on fuel dispensed. However, the adopted infrastructure crediting structure is a minor and appropriate departure (capped at a small portion of credits ≤ 5 percent of overall deficits), that strengthens the programs prior support for such infrastructure. The infrastructure crediting will help to achieve the Governor's goals of 10,000 DC Fast Chargers and 200 hydrogen stations by 2025, and 5 million ZEVs on the

road by 2030. We strongly disagree with the comment that the proposed infrastructure crediting provisions would take the State off track to meet SB 32 goals.

I-3. *Recommendations Provided, Although Opposed to Provision*

I-3.1. Comment: Fourth, while we recognize the importance of hydrogen as a low carbon and zero-emission fuel, we do not support the stakeholder proposal to provide credits based on infrastructure capacity, rather than fuel sold.

With that said, if the Board does decide to proceed, we do propose some importance boundaries on this approach in our written comments and encourage you to look at those. (UCS2_T53-6)

Agency Response: Please see Response I-2 in this chapter and Response I-3.1 in Chapter V.

I-3.2. Comment: If the Board does proceed with further consideration of such a proposal, it is important that such provisions be strictly limited to prevent potential gaming, diluting the value of LCFS credits, and setting a precedent that other fuels could follow to further weaken the program. Specifically, we encourage the board to

- Ramp down this crediting pathway over time, ensuring that early support for infrastructure transitions rapidly to credit generation based on low carbon fuel sales.
- Phase out the infrastructure pathway by 2025 or once the first 200 stations are built, whichever comes first, and limit individual stations to no more than ten years of credits for unused capacity.
- Ensure that crediting for infrastructure is based on a realistic estimate of future retail throughput, rather than a theoretical throughput of 100 percent utilization 24 hours a day
- Ensure that the initiative does not dilute the program by capping total credit generation at no more than 1 percent of the annual credit obligation in any given year.
- Restrict eligibility for similar pathways to zero emissions technologies with best in class carbon intensities. (UCS1_53-6a)

Agency Response: Staff included several provisions similar to those suggested by the commenter. Responses to each of the commenter's suggestions are included below:

- HRI credits are generated based on the difference in fuel throughput and the nameplate refueling capacity at a given hydrogen station. In this way, HRI credit generation "self-sunsets" over time as station utilization increases with greater ZEV penetration.

- Staff has not instituted a limit on the total stations that can be approved under the HRI provision, but did limit the total HRI credits per quarter to 2.5 percent of deficits for the prior quarter (please see Response I-6.7 in this chapter for the rationale). In addition, staff will only accept HRI applications through year-end 2025, providing an effective incentive to apply quickly for credit generation. After reviewing stakeholder feedback and conducting internal modeling of hydrogen station economics, staff instituted a 15-year crediting period for HRI credit generation, which staff believes is appropriate for expanding the hydrogen network and reaching the goals established in Executive Order B-48-18.
- In response to stakeholder feedback, staff proposed to use a 24-hour nameplate refueling capacity using an established fueling profile that does not assume 100 percent utilization over the 24-hour period. Please see Response I-8.1 in Chapter V for a further description of the calculation of station nameplate capacity.
- Please see Response I-11.1 in Chapter V regarding the decision to cap total HRI credits at 2.5 percent of the previous quarter's deficits. Incorporation of HRI crediting, if capped at 2.5 percent, is not expected to dilute the credit market and significantly reduce overall revenue for entities reporting alternative fuels.
- Staff was directed to consider infrastructure crediting for ZEV infrastructure only, and so has designed the proposal around these fuels. Regarding the carbon intensity used for ZEV infrastructure crediting, please see Response I-5.1 in this chapter.

I-3.3. Comment: The last thing I'll note, on the hydrogen proposal -- and I have 10 seconds so I'm going to go quick. We hope that if that proposal is advanced, that it would be tech neutral and include EV charging. And we would also hope that there is some sort of backstop to ensure that any capacity credit that's given ultimately is tied to an actual fuel -- renewable fuel distributed into the system. (TESLA2_T26-6)

> **Agency Response:** ZEV infrastructure crediting includes both DC Fast Chargers for EV charging and hydrogen refueling stations. Dispensed fuel is tied to this infrastructure crediting in specific ways. For hydrogen, the infrastructure crediting calculation is tied to the weighted average CI of dispensed hydrogen across a company's refueling network in California. In addition, infrastructure credits will not be issued for any FSE for which no fuel is dispensed in a given quarter.

I-4. *Reporting and Recordkeeping Requirements*

Comment: (e) *Reporting Actual Quantity of Hydrogen Sold.* Each hydrogen refueling infrastructure project must submit to the Executive Officer the annual actual quantity of hydrogen sold every year.

(f) *Recordkeeping.* Each applicant that receives approval as a hydrogen infrastructure project must maintain records for the project. For such a project, the applicant must maintain records for at least five years. At a minimum, the following records must be kept:

(1) The quarterly volume of hydrogen fuel actually sold.

(2) The carbon intensity of the hydrogen fuel actually sold.

(3) Any additional records that the Executive Officer requires to be kept in pursuant to section 95490.5, and records that demonstrate compliance with all special limitations and operating conditions specified pursuant to section 95490.5. (H2IND1_30-14)

Agency Response: Staff has included a list of reporting and recordkeeping requirements in section 95486.2(a)(6). This list includes station availability, company-wide renewable content of hydrogen dispensed, and cost and revenue data (detailed in subsection (C)). As discussed previously, station availability data is used in the HRI credit calculation. Reporting the renewable content percentage ensures that the company is in compliance with the 40 percent renewables requirement mandated in this subarticle. Cost and revenue data is necessary for staff to track performance of the program on an ongoing basis and to make adjustments as needed in future rulemakings.

Hydrogen fuel dispensed and associated Fuel Pathway Code, which specifies the CI value, must be reported to staff quarterly, pursuant to section 95491(a). This requirement is not specific to stations receiving HRI credits.

I-5. *CI and Renewable Content of Dispensed Hydrogen*

I-5.1. Multiple Comments: *CI and Renewable Content Requirement*

Comment: (B) The Fuel Pathway Carbon Intensity Value for use in the Hydrogen Infrastructure Pathway for each Hydrogen Refueling Facility registered under section 95488.2(c) shall be the same as the Fuel Pathway Carbon Intensity Value Certified for the/by the applicant for that Hydrogen Refueling Facility under sections 95488.1 (Fuel Pathway Classification), 95488.2 (Pathway Registration and Facility Registration), 95488.3 (Calculation of Fuel Pathway Carbon Intensities), 95488.4 (Lookup Table Fuel Pathway Application Requirements and Certification Process), 95488.5 (Tier 1 Fuel Pathway Application Requirements and Certification Process), 95488.6 (Tier 2 Fuel Pathway Application Requirements and Certification Process), 95488.7 (Fuel Pathway Application Requirements Applying to All Classifications), 95488.8 (Special Circumstances for Fuel Pathway Applications), and Maintained under section 95488.9. (H2IND1_30-9)

Comment: To ensure reduction in the carbon intensity of the hydrogen fuel supplied to refueling facilities receiving hydrogen investment credits, an eligibility threshold of either 40% renewable content per the current CEC GFO definitions for feedstocks or 75 gCO2e/MJ carbon intensity ensures crediting only for “best in class fuel” going

beyond requirements for hydrogen under SB 1505 for 33% renewable content and 30% reduction in carbon intensity compared to gasoline. Furthermore, it ensures a "no regrets" policy for LCFS goals by ensuring hydrogen credited under the proposed pathway is also best in class across other low-carbon fuels.[2]

[2] For example, using the median CI of existing LCFS pathways for renewable source hydrogen of approximately 6 gCO2e/MJ and the CI of 121.43 gCO2e/MJ for the HYF pathway (central reforming of natural gas with gaseous delivery), the requirement for 40% renewable source hydrogen production would deliver 75.26 gCO2e/MJ CI or 30.10 EER-adjusted CI (68% reduction from the current reference gasoline). This carbon intensity would be "best in class" for hydrogen and also amongst other low-carbon fuels:

- Electricity: ca. 105 gCO2e/MJ CI or 30.9 EER-adjusted CI from California Grid electricity.
- Ethanol: ca. 40 – 80 gCO2e/MJ and EER-adjusted CI (except outliers)
- CNG: ca. 60 – 100 gCO2e/MJ CI and EER-adjusted CI
- RNG: ca. 40 – 75 gCO2e/MJ and EER-adjusted CI (except outliers)
- Renewable Diesel: ca. 20 – 40 gCO2e/MJ and EER-adjusted CI (except outliers)
- Biodiesel: ca. 15 – 60 gCO2e/MJ and EER-adjusted CI

…

(2) A registered Hydrogen Refueling Facility is eligible to receive Hydrogen Infrastructure Investment Credits in each reporting period provided that at least one of the following conditions is met in the reporting period: (i) the registered Hydrogen Refueling Facility is supplied with an average of 40% or more renewable source hydrogen during the reporting period; (ii) the average of all registered Hydrogen Refueling Facilities for the Fuel Reporting Entity are supplied with an average of 40% or more renewable source hydrogen during the reporting period; (iii) the registered Hydrogen Refueling Facility is supplied with hydrogen with an average of 75 gCO2e/MJ carbon intensity or less during the reporting period; or (iv) the average of all registered Hydrogen Refueling Facilities for the Fuel Reporting Entity are supplied with hydrogen with an average of 75 gCO2e/MJ carbon intensity or less during the reporting period. (H2IND1_30-5a)

Agency Response: Staff agrees with the goal of incentivizing lower CI hydrogen through stations receiving HRI credits. Staff also agrees that hydrogen dispensed by such stations must meet the renewable content requirements of SB 1505. As part of the 15-day modifications to the original proposal, staff proposed that the CI and renewable content of hydrogen used for HRI crediting will be calculated on a company-wide weighted average basis for each quarter. This approach broadly incentivizes the production of lower-CI hydrogen, without directly penalizing stations with more limited access to renewables. Please see Response I-5, Carbon Intensity and Renewable Content Requirement for HRI Crediting, in Chapter V regarding staff's requirements for the maximum CI and minimum renewable content percentage.

I-6. *Hydrogen Infrastructure Pathway*

I-6.1. Comment: We are pleased to submit for consideration by the California Air Resources Board (ARB) a proposal for a *Hydrogen Infrastructure Pathway* to generate credits under the Low Carbon Fuel Standard (LCFS). We are proposing this to

accelerate the build out of hydrogen refueling stations and reducing carbon intensity of hydrogen supply by providing LCFS credits based on installed fuel dispensing capacity.

We believe this Hydrogen Infrastructure Pathway can provide an effective incentive for expanding zero-emission vehicle infrastructure while remaining consistent with the LCFS policy intent by accomplishing the following during the early years of Fuel Cell Electric Vehicle (FCEV) deployment:

- partially offset the initial lower utilization of hydrogen refueling stations, thereby supporting refueling network development to increase the availability of hydrogen;
- enable efficient development of hydrogen refueling stations at a sustained pace and scale to achieve significant cost reduction, for efficient use of public and private funds and reducing the cost of low-carbon fuels for Californians;
- enable the incentive structure already in place in the LCFS to reduce the carbon intensity of hydrogen through increasing renewable content;
- become self-balancing and sun-setting, with credit generation through the Hydrogen Infrastructure Pathway decreasing over time as hydrogen sales and station utilization increase;
- ensure best-in-class carbon intensity and infrastructure quality through eligibility conditions;
- ensure no material or unintended impacts to the overall LCFS policy and stakeholders through fixed limits on duration, infrastructure capacity, and credit generation.

This is a revision to the proposal originally introduced at the ARB workshop on 6 November 2017, and submitted in writing to the ARB on 28 November 2017. This revision is intended to align with the objectives and direction in Executive Order B-48-18 and to build upon the original proposal to ensure it is effective for increasing the supply of hydrogen refueling stations and decreasing the carbon intensity of this Zero Emission Vehicle (ZEV) fuel without having material or unintended impact to the overall LCFS policy and stakeholders.

A detailed description of the proposal as well as proposed regulatory language is attached.

…

Attachment 1 – Detailed Discussion of the Hydrogen Infrastructure Pathway

1. Introduction: expanding zero-emission vehicle infrastructure through the LCFS program

The Low Carbon Fuel Standard (LCFS) was established by Executive Order S-01-07, pursuant to AB32, to reduce the carbon intensity of California's transportation fuels.

With Executive Order B-48-18, California announced a target of 5 million ZEV by 2030 and an eight-year $2.5 billion investment initiative to continue the state's clean vehicle rebates and spur more infrastructure investments. The Executive Order also specifically calls for state entities to collaborate with stakeholders to implement this order, including "expand zero-emission vehicle infrastructure through the Low Carbon Fuel Standard Program."

Reaching California's goals for greenhouse gas and criteria pollutant emission reductions necessitate the acceleration and scaling up of very low-emission options in the transportation sector. This will require consumer choice across all vehicle segments and refueling/recharging modes of use, and will require growth in California's energy infrastructure to accommodate demand from the transportation sector as well as increasing supply from renewable sources. To be successful, a portfolio of Zero Emission Vehicles (ZEV) including Fuel Cell Electric Vehicles (FCEV), Battery Electric Vehicles (BEV) and Plug-in Hybrid Electric Vehicles (PHEV) will be needed. Of these, FCEVs have the benefit of long range, fast refuel time and scalability; and is a very good ZEV option for those without the ability to charge at home. The refueling model for FCEVs is similar to that of conventional internal combustion engine vehicles in that it is done at a refueling station. As such, hydrogen refueling station capacity, coverage, and cost are prerequisites for a successful FCEV market. The initial low utilization of new refueling infrastructure during early stages of the market limits the pace of development and availability of this fuel, and increases the cost relative to traditional transportation fuels, all of which inhibit customer adoption. However, with modest scale in sustained development of hydrogen refueling infrastructure, it has been shown that the cost of hydrogen refueling stations can be reduced by 50% or more. A significant portion of cost reduction in hydrogen refueling stations serving light-duty vehicles can transfer to stations serving heavy-duty vehicles.

…

In summary and as discussed above, the Hydrogen Infrastructure Pathway accomplishes the following during early years of FCEV deployment:

- partially offsets the initial low utilization of hydrogen refueling stations, thereby supporting refueling network development to increase the availability of this fuel;
- enables efficient development of hydrogen refueling stations at a sustained pace and scale to achieve significant cost reduction, for efficient use of public and private funds and reducing the cost of low-carbon fuels for Californians;
- enables the incentive structure already in place in the LCFS to reduce the carbon intensity of hydrogen through increasing renewable content;
- becomes self-balancing and sun-setting, with credit generation through the Hydrogen Infrastructure Pathway decreasing over time as hydrogen sales and station utilization increase;
- ensures best-in-class carbon intensity and infrastructure quality through eligibility conditions;

- ensures no material or unintended impacts to the overall LCFS policy and stakeholders through fixed limits on duration, infrastructure capacity, and credit generation.

This pathway would create a durable and scalable mechanism to partially offset low utilization during early commercialization of hydrogen fuel. (H2IND1_30-1)

> **Agency Response:** Staff agrees in principle with the objectives stated for the proposal submitted by the commenter. Please see Responses I-4, I-5.1, I-6.2, I-6.3, I-6.4, I-6.5, I-6.6, I-6.7, I-6.8, I-6.9, I-6.10, I-6.11, I-6.12, I-6.13, I-6.14, and I-6.15 in this chapter regarding specific issues raised by the commenter. Please see also Response I-1, Support for the Proposal on Hydrogen Infrastructure Capacity Credits and Infrastructure Credits for DC Fast Chargers, in this chapter, regarding the impetus for and design of this provision.

I-6.2. Comment: The Hydrogen Infrastructure Pathway would generate LCFS credits based on installed hydrogen station fuel dispensing capacity. The number of credits generated by a hydrogen refueling station would be equal to the credits generated through hydrogen sales (current policy) plus credits for the remaining capacity of the station (new Hydrogen Infrastructure Pathway).

This proposal has two objectives: 1) supporting hydrogen fueling stations during low utilization for station network expansion, and 2) incentivizing the selection of lower-CI hydrogen production pathways.

The Hydrogen Infrastructure Pathway would be subject to eligibility criteria and boundaries on credit generation, pathway duration, and administration including documentation and reporting to protect against unintended impact to the LCFS policy and stakeholders. (H2IND1_30-2)

> **Agency Response:** Staff agrees with the principles presented in this comment. Staff's proposal introduced as part of 15-day modifications to the original amendments proposal incorporated the mechanism that LCFS credits for hydrogen infrastructure would be based on the difference between the station capacity and station throughput. Staff also incorporated provisions that support the two objectives listed above. See section 95486.2(a) for eligibility requirements, application requirements, the application approval process, requirements to generate credits, the methodology for calculating infrastructure credits, reporting and recordkeeping requirements, and a process for increasing capacity for further crediting.

I-6.3. Comment: 1) *Support for hydrogen fueling station network expansion*

This policy can incentivize a significant increase in the rate of hydrogen refueling station buildout, which supports the ability of automakers to deploy FCEVs into the market at higher volumes, and is an important step towards both commercialization and customer adoption of this best-in-class low-carbon fuel for FCEVs. Such acceleration can create

both a positive cycle with cost reduction for further expansion, and will be important to realizing Executive Order B-48-18 target of 200 hydrogen refueling stations by 2025 which will require doubling of the historical pace to achieve approximately 2 stations opening per month or 24 stations per year.[1] In particular:

[1] As of December 2017, a total of 65 hydrogen refueling stations were funded through the ARFVTP program and 31 were open for retail. The pace of station openings from Q3 2015 through Q4 2017 has averaged approximately 3 stations per quarter or 1 station per month, although only six stations became open retail in 2017. The average station development time has decreased to approximately 25 months (excluding outliers). Source: California Energy Commission and California Air Resources Board, Joint Agency Staff Report on Assembly Bill 8: 2017 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California. To deliver the remaining 135 stations to achieve a total of 200 open retail by 2025 would require an average pace of approximately 24 per year or 2 stations per month even if begun immediately and with an average development time of 24 months.

- For commercialization and further expansion of the hydrogen refueling network, cost reduction in the refueling station capital and operating costs are key. A pace of approximately 30 stations per year leading to a network density of approximately 60 stations in a service territory has been shown to reduce station capital and operating costs by 50% from current benchmarks.
- For customer adoption, both the availability of hydrogen fuel through expansion of refueling network coverage and retail price reduction are needed, both of which can be accomplished through acceleration and scale as cost reduction translates to retail prices in a competitive market.

Adopting the proposed Hydrogen Infrastructure Pathway may impact business decisions for the buildout of hydrogen refueling stations. The following example is intended to show this potential impact.

- In the case of a station with 400 kg/d capacity and initial utilization of 15% increasing to 80%in its 10th year of operation, the cumulative number of LCFS credits generated over 15 years under the existing fuel pathways would range from 4,950 with the HYFL pathway (liquefied hydrogen produced by reforming natural gas) to 29,000 with the HYER pathway (compressed hydrogen produced by solar- or wind- electrolysis). Assuming $100/credit market price and 10% discount rate, the present value of these credits supporting investment in the hydrogen refueling station ranges from $230,000 to $1,250,000.
- With adoption of the proposed Hydrogen Infrastructure Pathway, the incremental infrastructure investment credits generated under this example would range from 5,000 with the HYFL pathway to 24,000 with the HYER pathway, and yield an incremental present value supporting infrastructure investment of $330,000 to $1,480,000.

The Hydrogen Infrastructure Pathway in this example more than doubles the support from LCFS credit generation to investments in expanding the refueling station network by partially offsetting the low initial utilization. In fact, the combination of fuel and infrastructure pathways in this example sum to the total incentive the existing LCFS fuel pathway alone would provide to hydrogen refueling in a mature market with 100%

station utilization: from 10,000 to 53,000 cumulative credits with the HYFL and HYER pathways, providing $560,000 to $2,740,000 present value of credits to support investment in the hydrogen refueling station.

Furthermore, the support for infrastructure investment provided by LCFS credit revenue is scalable, meaning efficient programs of infrastructure development may be possible, and the nature of infrastructure investment credits being inversely proportional to station utilization can partially reduce the risk on initial station utilization. The impact to support infrastructure investment from the proposed hydrogen infrastructure pathway may be multiplied by the significant cost reduction enabled. (H2IND1_30-3)

> **Agency Response:** Staff agrees that the current pace of hydrogen station development is insufficient to meet the Governor's target of 200 stations by 2025. Staff believes that the HRI crediting provisions proposed by staff will indeed encourage more rapid expansion of the existing hydrogen network in order to bring down capital costs and pave the way for greater deployment of zero emission vehicles.

I-6.4. Comment: The proposal can also provide incentive for a significant acceleration in the decrease of carbon intensity in the production of hydrogen fuel, which in conjunction with increasing customer adoption of FCEV, can make a material contribution to achieving the LCFS goals for decreasing carbon intensity and emissions.

The contribution to emission reduction of 200 hydrogen refueling stations in 2025 will depend on the number of vehicles supported (thus volume of hydrogen displacing gasoline) and the carbon intensity of the hydrogen fuel. The following example is meant to illustrate the potential impact of policy to encourage scale and acceleration with fuel decarbonization such as the Hydrogen Infrastructure Pathway we are proposing.

- With relatively small stations developed to ensure adequate initial utilization (e.g., 200 kg/d capacity), supplied with conventional hydrogen produced from reformation of natural gas to keep cost as low as possible (e.g., HYGN001 pathway with 151 gCO2e/MJ), it might be that 200 vehicles per station are supported at 70% station utilization each using an average of 0.7 kg/d. In this example, the total number of FCEV supported by 200 hydrogen refueling stations would be 40,000 – just 2.7% of the target for 1.5 million ZEV on-road in 2025 – and the hydrogen displacing gasoline would be 28 metric tons per day, 10,220 metric tons per year, and approximately 90,000 MT CO2/year emission reduction.
- With somewhat larger stations developed to support market growth despite low initial utilization (e.g., 400 kg/d), supplied with renewable source hydrogen produced from renewable natural gas and/or renewable source electricity (e.g., HYGE200L pathway with 0 gCO2e/MJ or HYGLF200L pathway with -5 gCO2e/MJ), it might be that 400 vehicles per station are supported at 70% station utilization each using an average of 0.7 kg/d. In this example, the total number of FCEV supported by 200 hydrogen refueling stations would be 80,000 – contributing 5.3% to the target for 1.5 million ZEV on-road – and the

hydrogen displacing gasoline would be 56 metric tons per day, 20,440 metric tons per year, and more than 550,000 MT CO2/year emission reduction.

Adopting the proposed Hydrogen Infrastructure Pathway may impact business decisions for decarbonizing hydrogen production pathways. As the LCFS policy is intended, the revenue from LCFS credit generation can support the selection of higher-cost lower-carbon production pathways if the difference in revenue from credit generation more than offsets the incremental cost of the lower-carbon production pathway. The following example is intended to show this potential impact.

- Again, in the case of a station with 400 kg/d capacity and initial utilization of 15% increasing to 80% in its 10th year of operation, the present value of fuel pathway credits received over 15 years assuming $100/credit and 10% discount rate is equal to $0.23/kg for the HYFL pathway (liquefied hydrogen produced by reforming natural gas) and $1.25/kg for the HYER pathway (compressed hydrogen produced by solar- or wind-electrolysis). Thus, the existing fuel pathway could support selection of low-carbon renewable-source hydrogen production if the incremental cost is less than approximately $1/kg in this example.
- With adoption of the proposed Hydrogen Infrastructure Pathway, the incremental present value of cumulative infrastructure investment credits received over this period is equal to$0.33/kg with the HYFL pathway and $1.48/kg with the HYER pathway. Thus, adoption of the proposed Hydrogen Infrastructure Pathway could increase support for selection of low-carbon renewable-source hydrogen production with incremental cost of as much as $2.17/kg in this example.

Once again, the Hydrogen Infrastructure Pathway in this example more than doubles the support from LCFS credit generation to selection of low-carbon hydrogen production pathways by partially offsetting the low initial utilization. In fact, the combination of fuel and infrastructure pathways in this example sum to the total incentive the existing LCFS fuel pathway alone would provide to hydrogen refueling in a mature market with 100% station utilization: from $0.56/kg to $2.74/kg credit value with the HYFL and HYER pathways. (H2IND1_30-4)

Agency Response: The economic results presented by the commenter reflect an analysis of the proposal put forth by the hydrogen community as part of the 45-day comment period. Staff did not attempt to corroborate this analysis. However, staff performed an economic analysis of the 15-day change proposal and presented this analysis to stakeholders at the June 20, 2018 workshop. Staff agrees in principle that staff's proposal should provide sufficient economic returns to build and operate stations and provide higher cost, low-CI hydrogen, even when initial throughput is low.

I-6.5. Comment: Even as the proposed Hydrogen Infrastructure Pathway encourages hydrogen refueling infrastructure development, it is self-balancing and sun-setting with the quantity of LCFS credits generated through the Hydrogen Infrastructure Pathway

decreasing as sales of hydrogen fuel increase, and naturally within the LCFS construct as the CI reduction target increases.

The Hydrogen Infrastructure Pathway as proposed also has several elements to ensure it aligns incentives for progress toward LCFS goals. (H2IND1_30-5)

> **Agency Response:** Please see Response I-6.1 in this chapter regarding the commenter's suggestion that HRI credits should decrease as credits for fuel dispensed increase. Please see Responses I-5.1, I-6.6, I-6.7, I-6.8, and I-6.13 in this chapter regarding the suggested elements proposed by the commenter.

I-6.6. Comment: The natural sunset to Hydrogen Infrastructure Pathway credit generation as station utilization and fuel sales increase is also limited within fixed caps to ensure the pathway provides incentive for early infrastructure development for a defined maximum scale that will not unduly impact the LCFS policy objectives, credit market, or other LCFS stakeholders.

- The time period for qualification for a hydrogen refueling facility into the hydrogen infrastructure pathway is limited to 10 years, approximately through year-end 2028, which is generally aligned with the expected period of pre-commercialization for hydrogen fuel during which increasing utilization and decreasing cost are improving viable market conditions.
- The maximum limit on the percentage of nameplate capacity eligible to receive hydrogen infrastructure investment credits – the "Maximum Capacity Fraction Cap" – declines from 100% to 40% over the 15 years of eligibility for each hydrogen refueling facility, which is generally aligned with the expected increase in hydrogen refueling facility utilization as more FCEV enter the market.

…

(C) Limitations on Credit Generation

> *(i) The number of* Hydrogen Infrastructure Investment Credits generated may not exceed the following percentage of the total possible credit generation from the Facility Nameplate Capacity:
>
> Year 1: 100.0%
>
> Year 2: 95.7%
>
> Year 3: 91.4%
>
> Year 4: 87.1%
>
> Year 5: 82.9%
>
> Year 6: 78.6%
>
> Year 7: 74.3%
>
> Year 8: 70.0%

Year 9: 65.7%

Year 10: 61.4%

Year 11: 57.1%

Year 12: 52.9%

Year 13: 48.6%

Year 14: 44.3%

Year 15: 40.0%

…

(2) *Duration.* A party may generate credits through the Hydrogen Infrastructure Pathway for each registered Hydrogen Refueling Facility for 15 years from the date of application approval. The Hydrogen Infrastructure Pathway provision will remain in effect for at least 10 years; any change to this policy shall not be retroactive.

(A) If a party increases the Facility Nameplate Refueling Capacity for a registered Hydrogen Refueling Facility during the period it is generating credits through the Hydrogen Infrastructure Pathway, the party may update the registered Facility Nameplate Refueling Capacity under 95488.2(c) and, upon approval, the credit calculation under 95490.5(b)(1) will use the new Facility Nameplate Refueling Capacity.

(B) A party may generate credits through the Hydrogen Infrastructure Pathway for the incremental Facility Nameplate Refueling Capacity under 95490.5 (b)(2)(A) for 15 years from the date of registration approval under 95488.2(c). (H2IND1_30-5b)

Agency Response: This comment provides details on the proposal put forth by the hydrogen community as part of the 45-day comment period. As part of the 15-day modifications to the proposed amendments, staff put forth an initial proposal that was based loosely on the stakeholder proposal but deviated in some important ways. First, staff proposed that applications for HRI crediting will be accepted through year end 2025, rather than 2028, provide more incentive to develop the State's hydrogen fueling network more quickly.

Second, staff chose not to include a declining cap on station capacity for HRI crediting, as proposed by the commenter above. Please see Response I-8.2 in Chapter V regarding staff's rationale for not including a declining cap.

Thirdly, staff agrees that a 15-year crediting period is appropriate for HRI crediting. Staff also believes it is reasonable for entities to receive HRI credits for expanded capacity. However, in staff's proposal the entity must demonstrate that throughput is equal to or greater than 50 percent of the original approved HRI refueling capacity. Please see Response I-6.2 in Chapter V regarding staff's decision to not reset the 15-year crediting period when a capacity expansion is approved.

I-6.7. Comment: To ensure the Hydrogen Infrastructure Pathway does not have material or unintended impact to the overall LCFS policy and stakeholders, the total number of hydrogen refueling facilities that can be qualified into the Hydrogen Infrastructure Pathway is limited to 500 stations, which is generally aligned with the pace of development required to meet targets for ZEV and associated infrastructure established in Executive Order B-48-18. Furthermore, the maximum refueling capacity eligible to receive hydrogen infrastructure investment credits is capped at 1,200 kg/d (the "Maximum Capacity Cap").

…

(3) Only the first 500 stations determined to be eligible may participate in this pathway.

(4) Facility Nameplate Refueling Capacity can be any amount, but the maximum cap of Facility Nameplate Refueling Capacity that may be deemed eligible for the Hydrogen Infrastructure Pathway is 1,200 kg/d. (H2IND1_30-5c)

Agency Response: This comment provides details on the proposal put forth by the hydrogen community as part of the 45-day comment period. As part of 15-day modifications to the proposed amendments, staff put forth an initial proposal that was based loosely on the stakeholder proposal but deviated in some important ways. Staff agrees that effective limits are needed for this provision to prevent unintended or adverse impacts to the overall program. Rather than limiting the total number of stations that may receive HRI credits, staff proposed to limit the total HRI credits generated in a given quarter to 2.5 percent of total deficits from the prior quarter. Setting a limit on stations leaves a degree of uncertainty regarding the overall program impact, due to the variability of station sizes and capacities. Please see also Response I-11.1 in Chapter V regarding the decision to cap total HRI credits at 2.5 percent. However, staff agrees that credits should not be issued for any capacity over 1,200 kg, and has included this provision in the final proposal.

I-6.8. Comment: The Hydrogen Infrastructure Pathway as proposed also addresses the following potential unintended consequences to ensure a robust policy that will not create perverse incentives or unintended consequences. In particular, the following provisions protect against over-building hydrogen refueling facilities with poor quality and/or location in pursuit of hydrogen infrastructure investment credits.

- Station Design Quality: eligibility requires compliance with codes and standards as well as current station performance requirements to ensure stations deliver the fueling performance expected at the time of certification.[3]

  [3] The California Air Resources Board may adopt a third-party engineering analytic model to certify station capacity in much the way the CI for proposed pathways is certified today: the applicant is required to submit requisite data for modeling, including documentation; the ARB uses the data supplied once verified with the third party model to simulate, verify, and certify the station capacity and fueling performance.

- Station Operation Quality: eligibility requires a minimum of 90% availability to ensure customer satisfaction with the dependability of hydrogen refueling;

stations not able to maintain this requirement would temporarily stop receiving hydrogen investment credits until such time as the requirement is met.

…

- Over-building Capacity: excessive capacity is limited by the Maximum Capacity Cap and Maximum Capacity Fraction Cap as discussed above.
- Refueling Network Coverage: continuation of grant funding for hydrogen refueling station development through the ARFVTP program can complement the proposed LCFS Hydrogen Infrastructure Pathway by ensuring refueling network coverage continues to grow in an efficient manner through combination of the CHIT model and OEM priority areas.

…

(ii) A hydrogen refueling station will only generate Hydrogen Infrastructure Investment Credits in months where the station availability as reported in the Station Operational Status System (SOSS) was 90% or greater. (H2IND1_30-5d)

Agency Response: This comment provides details on the proposal put forth by the hydrogen community as part of the 45-day comment period. Staff included several provisions similar to the commenter's suggestions, in an effort to maintain station quality and appropriately credit facilities.

- Staff included requirements in section 95486.2(a)(4)(D) regarding station operability and permitting prior to credit generation. Some examples include requirements that the station owner fully commission the station, and subject the fueling dispensers to type evaluation according to the California Type Evaluation Program (CETP) administered by the California Department of Food and Agriculture.
- Station availability is critical for the consumer experience, and has been included as an input in the HRI credit calculation. Please see Response I-4.1 in Chapter V for a description of why staff did not include a threshold of availability (below which no credits are earned).
- Please see Response I-6.7 in this chapter regarding the maximum hydrogen capacity cap and Response I-8.2 in Chapter V regarding the decision not to include a declining cap on capacity.
- Staff expects that several stations are likely to apply for, and possibly receive, grant funding from sources other than the LCFS. Stations that receive grants from the CEC GFO process will have already been evaluated based on station location and assessed a CHIT score. LCFS staff will not depend upon CHIT scores to approve applications for HRI crediting, but the Executive Officer has authority to exercise discretion when evaluating the required applicant justification for the station location and the overall contribution to the hydrogen refueling network.

I-6.9. Comment: The potential impact of the proposed Hydrogen Infrastructure Pathway on the overall LCFS policy and stakeholders will depend on its success in creating an effective incentive to expand hydrogen refueling infrastructure and decarbonize hydrogen production, and the transition time for industry to respond with investments. The pace and number of hydrogen refueling stations remains largely determined by government policy.

For example, with the pace of station development suggested by Executive Order B-48-18 of approximately 20 stations per year, current average station size of approximately 190 kg/d and 22%average utilization, supplied with 33% renewable hydrogen, the 200 stations by 2025 and implied 260 stations through 2028 (10 years of the proposed policy) could generate an additional 1% above current LCFS credit generation for this period.[4] If, for example, station size were to double over this period to an average of 400 kg/d, average utilization were to increase to 70%, and the hydrogen supply were to become 100% renewable, the increase over current LCFS credit generation would still be only 4 percent.

[4] As of December, 2017 there were 31 hydrogen refueling stations open retail with combined total capacity of 5,950 kg/d, and dispensing approximately 1,300 k/d in total. Source: California Energy Commission and California Air Resources Board, Joint Agency Staff Report on Assembly Bill 8: 2017 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California.

Two cases are defined here as illustrative for a pace of development achieving 450 hydrogen refueling stations in 2030 and continuing the previous examples for increase in station utilization:

- High Case: with successful incentive, hydrogen supply may come from renewable sources (e.g., the HYER pathway for solar- and wind-electrolysis) and station capacity may increase rapidly overtime to support a growing demand from FCEV, from the current average of 230 kg/d to 1,000 kg/d for new stations in 2030. In this case, the cumulative hydrogen infrastructure investment credits generated over 15 years from 2019 – 2033 is less than 4 percent of the total LCFS credits the ARB expects to be generated under the "Project/LD/Low ZEV/20%" scenario.
- Low Case: with unsuccessful incentive, hydrogen supply may continue to come from reformation of natural gas (e.g., the HFL pathway) and station capacity may increase slowly over time, from the current average of 230 kg/d to 400 kg/d for new stations in 2030. In this case, the cumulative hydrogen infrastructure investment credits generated over 15 years from 2019 – 2033 is less than 1 percent of the total LCFS credits the ARB expects to be generated under the "Project/LD/Low ZEV/20%" scenario. (H2IND1_30-6)

  Agency Response: Staff's believes that the infrastructure crediting provisions can be successful without exceeding 2.5 percent of total deficits from the prior quarter. Staff's modeling shows that this provision, if fully utilized by hydrogen station developers, could help achieve the goal outlined in Executive Order B-48-18 of 200 hydrogen stations by 2025, while at the same time helping to reduce retail hydrogen prices and to incentivize the sale of lower CI hydrogen.

I-6.10. Comment: *§ 95488.2* Pathway Registration and Facility Registration *is amended by adding at the end:*

(c): Hydrogen Refueling Facility Registration. All hydrogen refueling stations applying to generate credits through the Hydrogen Infrastructure Pathway per section 95490.5 must be registered in the AFP. All of the following fields that apply are required:

(1) Refueling station company name and full mailing address

(2) Company contact person's contact information

a. Name

b. Title or position

c. Phone number

d. Mobile phone number

e. Email address

f. Company web site URL

(3) Facility name (or names, if more than one facility is covered by the proposed pathways)

(4) Facility address (or addresses, if more than one facility is covered by the proposed pathways)

(5) Facility geographical coordinates (for each facility covered by the proposed pathways). Coordinates can be reported using either the latitude and longitude or the Universal Transverse Mercator coordinate systems.

(6) Facility contact person's contact information

a. Name

b. Title or Position

c. Phone number

d. Mobile phone number

e. Email address

(7) ***Facility Nameplate Refueling Capacity*** *as defined in 95490.5 (b) (1) (A). This information is required for each facility covered by the proposed pathways.*

(8) ***Additional information as requested by the Executive Officer under section 95490.5(c) pertaining*** *to station design and specifications, including documentation, in order to certify the Facility Nameplate Refueling Capacity, compliance with applicable codes and standards, and Station Performance Requirements.*

…

(1) *Credit Calculation. Subject to the limitations in paragraph (c) below,* the number of Hydrogen Infrastructure Investment Credits generated shall be equal to the (Facility Nameplate Refueling Capacity – Quantity of Hydrogen Sold) x (Credits per unit Hydrogen according to the Fuel Pathway Carbon Intensity Value certified for that Hydrogen Refueling Facility).

(A) Facility Nameplate Refueling Capacity in kilograms hydrogen per 24-hour day shall be the 24-hour fueling capacity as registered under Section 95488.2(c) and defined in applicable codes and standards or either the Station Performance Requirements in the most recent Application Manual for Grant Funding Opportunity for Light Duty Vehicle Hydrogen Refueling Infrastructure under the Alternative Renewable Fuel and Vehicle Technology Program from the California Energy Commission or similar manual adopted by the Air Resources Board if more recent or applied to Hydrogen Refueling Facilities serving medium or heavy-duty vehicles. (H2IND1_30-7)

Agency Response: This comment provides details on the proposal put forth by the hydrogen community as part of the 45-day comment period. As part of 15-day modifications to the proposed amendments, staff put forth an initial proposal that was based loosely on the stakeholder proposal but deviated in some important ways. Staff included several elements from the above list regarding general applicant and facility information and also specified that applicants provide detailed information on station design and specifications in order to verify station capacity calculations. Staff did not adopt the definition of Facility Nameplate Refueling Capacity suggested by the commenter (24 hour capacity). In response to stakeholder feedback, staff proposed to use a 24-hour nameplate refueling capacity using an established fueling profile. Please see Response I-8.1 in Chapter V for a further description of the calculation of station nameplate capacity.

I-6.11. Comment: § 95490.5 Provisions for Hydrogen Refueling Infrastructure.

(a) *Eligibility.*

(1) Reporting Entities for Hydrogen as defined in section 95483(f)(1) are eligible to receive Hydrogen Infrastructure Investment Credits for Hydrogen Refueling Facilities registered under Section 95488.2(c) serving light, medium, and/or heavy-duty vehicles that comply with applicable codes and standards as well as either the Station Performance Requirements in the most recent Application

Manual for Grant Funding Opportunity for Light Duty Vehicle Hydrogen Refueling Infrastructure under the Alternative Renewable Fuel and Vehicle Technology Program from the California Energy Commission or similar manual adopted by the Air Resources Board if more recent or applied to Hydrogen Refueling Facilities serving medium or heavy-duty vehicles. (H2IND1_30-8)

Agency Response: This comment provides details on the proposal put forth by the hydrogen community as part of the 45-day comment period. As part of 15-day modifications to the proposed amendments, staff put forth an initial proposal that was based loosely on the stakeholder proposal but deviated in some important ways. Staff agrees that station owners, who are defined as the first fuel reporting entity for hydrogen fuel, would receive HRI credits if an application was approved for crediting. HRI credits may only be generated based on fueling capacity that is open to the general public, excluding stations serving private fleets and stations only serving heavy-duty vehicles. In addition, please see Response I-2 in Chapter V regarding the use of the light-duty vehicle EER value in the crediting equation. Please see also Response I-6.8 in this chapter regarding requirements to generate HRI credits.

I-6.12. Comment: *(iii)* A hydrogen refueling station will only generate Hydrogen Infrastructure Investment Credits so long as it remains open to the public for refueling. If a hydrogen refueling station is closed to service by a regulatory authority for any reason, it will cease to generate Hydrogen Infrastructure Investment Credits until such time as the situation has been remedied and the hydrogen refueling station is allowed to re-open. (H2IND1_30-10)

Agency Response: This comment provides details on the proposal put forth by the hydrogen community as part of the 45-day comment period. As part of 15-day modifications to the proposed amendments, staff put forth an initial proposal that was based loosely on the stakeholder proposal but deviated in some important ways. Staff agrees that hydrogen stations receiving HRI credits must be open to the public. Station availability is critical for the consumer experience, and has been included as an input in the HRI credit calculation. If a station is closed to service, the lack of availability of the station will be reflected in the credit generation equation.

I-6.13. Comment: Hydrogen Fuel Quality: hydrogen purity and quality is tested periodically and audited by DMS, as with all other fuels. A station closed to service by a regulatory authority for any reason will cease to generate Hydrogen Investment Credits until such time as the situation has been remedied and the station is allowed to re-open.

…

(3) Fuel Quality

(A) The hydrogen refueling station, including the dispenser, shall dispense hydrogen that complies with the hydrogen quality requirements in CCR Title 4, Division 9, Chapter 6, Article 8, Sections 4180 and 4181 which adopts the Society of Automotive Engineers (SAE) International J2719: 2011"Hydrogen Fuel Quality for Fuel Cell Vehicles."

(B) The hydrogen refueling station shall conform with the provisions of SAE International J2601: 2016, Fueling Protocols for Light Duty and Medium Duty Gaseous Hydrogen Surface Vehicles (www.sae.org), or the most recent version of the standard published and promulgated by the SAE. (H2IND1_30-11)

Agency Response: This comment provides details on the proposal put forth by the hydrogen community as part of the 45-day comment period. As part of 15-day modifications to the proposed amendments, staff put forth an initial proposal that was based loosely on the stakeholder proposal but deviated in some important ways. Staff did not specify a single SAE fueling protocol, but instead required that the station must be fully commissioned and declared fit to service retail fuel cell vehicles, including a declaration that the station meets an appropriate SAE fueling protocol. Please see also the Response I-6.8 in this chapter regarding requirements to generate credits. Staff has not included requirements for ongoing verification of hydrogen fuel quality, as this is already handled by the California Dept. of Food and Agriculture. Regarding availability of the station, please see Response I-6.11 in this chapter and Response I-6.13 in Chapter V.

I-6.14. Comment: (c) *Applications.* An application must contain the following materials:

(1) The facility nameplate capacity as defined in Section 95490.5(b)(1)(A).

(2) The fuel pathway carbon intensity value as defined in Section 95490.5(b)(1)(B).

(3) A signed transmittal letter from the applicant attesting to the veracity of the information in the application packet. The transmittal letter shall be the original copy, be on company letterhead, be signed by an officer of the applicant with authority to attest to the veracity of the information in the application and to sign on behalf of the applicant.

(4) All documents (including spreadsheets and other items not in a standard document format) that are claimed to contain confidential business information (CBI) must prominently display the phrase "Contains Confidential Business Information" above the main document title and in a running header. Additionally, a separate, redacted version of such documents must also be submitted. The redacted versions must be approved by the applicant for posting to a public LCFS web site. Specific redactions must be replaced with the phrase "Confidential business information has been deleted by the applicant." This phrase must be displayed clearly wherever CBI has been redacted. If the applicant claims that information it submits is confidential, it must also provide contact information required in California Code of Regulations, title 17, section 91011.

(5) An applicant that submits any information or documentation in support of a proposed hydrogen infrastructure project must include a written statement clearly showing that the applicant understands and agrees that all information in the application not identified as confidential business information is subject to public disclosure pursuant to California Code of Regulations, title 17, sections 91000 through 91022 and the California Public Records Act (Government Code, §§. 6250 et seq.), and that information claimed by the applicant to be confidential might later be disclosed under section 91022 if the state board determines the information is subject to disclosure.

(6) An application, supporting documents, and all other relevant data or calculation or other documentation, except for the transmittal letter described in section 95490(a)(3)(D), shall be submitted electronically, such as via e-mail or an online-based interface, unless the Executive Officer has approved or requested another format. (H2IND1_30-12)

Agency Response: This comment provides details on the proposal put forth by the hydrogen community as part of the 45-day comment period. As part of 15-day modifications to the proposed amendments, staff put forth an initial proposal that was based loosely on the stakeholder proposal but deviated in some important ways. Staff included several requirements for HRI applications that are similar to those listed above, in section 95486.2(a)(2).

- Regarding the station nameplate capacity, please see Response I-6.10 in this chapter.
- The company-wide weighted average CI will be calculated by staff for each company receiving HRI credits, and will be applied automatically to the HRI credit generation calculation. However, the initial application must include the expected CI for each station individually, as well as the expected sources of hydrogen and the hydrogen delivery methods.
- Staff agrees that the applicant must attest to the veracity of the information in the application. Specific requirements for the attestation letter are included in section 95486.2(a)(2)(K).
- Staff also agrees that CBI must be declared at the point of application. Specific requirements for marking information as CBI are listed in section 95488.8(c) and also apply to HRI applications, pursuant to section 95486.2(a)(2)(L).
- Staff did not include a requirement that applicants submit a letter demonstrating their understanding that any materials not marked as CBI are subject to public disclosure. However, it is described in section 95486.2(a)(3)(D) that a pathway summary will be posted online for each approved station, including the station location, assigned identifier, number of dispensing units, HRI refueling capacity, and effective date range for HRI pathway crediting.

- Staff also has broad authority to request additional information needed to assess HRI applications, as stated in section 95486.2(a)(3)(B)3.

I-6.15. Comment: (d) *Application Approval Process.* An application must be approved by the Executive Officer before the hydrogen infrastructure project can generate credits under the LCFS regulation.

(1) After receipt of an application designated by the applicant as ready for formal evaluation, the Executive Officer shall advise the applicant in writing either that:

1. The application is complete, or

2. The application is incomplete, in which case the Executive Officer will identify which requirements have not been me. The applicant may submit additional information to correct deficiencies identified by the Executive Officer.

(2) After accepting an application as complete, the Executive Officer will post the application at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm. Public comments will be accepted for 10 calendar days following the date on which the application was posted. Only comments related to potential factual or methodological errors may be considered. The Executive Officer will forward to the applicant all comments identifying potential factual or methodological errors. Within 30 business days, the applicant shall either submit revisions to its application to the Executive Officer, or submit a detailed written response to the Executive Officer explaining why no revisions are necessary.

(3) If the Executive Officer finds that an application meets the requirements set forth in section 95490.5 the Executive Officer will take final action to approve the hydrogen infrastructure project. The Executive Officer may prescribe conditions of approval that contain special limitations, recordkeeping and reporting requirements, and operational conditions that the Executive Officer determines should apply to the project. If the Executive Officer finds that an application does not meet the requirements of section 95490.5, the application will not be approved, and the applicant will be notified in writing, and the basis for the disapproval shall be identified. (H2IND1_30-13)

Agency Response: This comment provides details on the proposal put forth by the hydrogen community as part of the 45-day comment period. As part of 15-day modifications to the proposed amendments, staff put forth an initial proposal that was based loosely on the stakeholder proposal but deviated in some important ways. Staff included similar language in section 95486.2(a)(3)(B) through (D). However, staff did not think it necessary to include a public comment period for each pathway, as suggested by the commenter. Staff also did not include language in this section specifically stating that the Executive Officer may prescribe specific operating conditions to each application, as this authority is implicit throughout the subarticle and is commonly used when certifying fuel pathway applications. Lastly, staff specifically stated that the Executive Officer may reject an application if the justification for the station location and capacity (required in

section 95486.2(a)(2)(J) is unsatisfactory. This provision allows the Executive Officer authority to exercise discretion in reviewing the appropriateness of station location and capacity and the overall contribution to the hydrogen refueling station network.

I-6.16. Comment: We'd also like to highlight an upcoming white paper on renewable hydrogen that identifies the critical role that the LCFS plays to advancing the scalable cost-effective renewable hydrogen marketplace. That paper will be released in the coming weeks in association with the California Hydrogen Business Council and the Leonardo DiCaprio Foundation.

A couple -- beyond extending the LCFS program, as staff recommends, which is so critical to incentivizing, production of a renewable hydrogen, while lowering prices to consumers because LCFS credit values increase along with the amount of renewable content in the fuel. (EIN2_T30-3)

> **Agency response:** Staff is committed to develop provisions under LCFS to promote a variety of low carbon transportation fuels, including renewable hydrogen, to help achieve the State's emission reduction goals. We support the efforts of other organizations working toward the common goal.

I-7. *Other Agencies Already Support Infrastructure Deployment*

Comment: Capacity-based credits also risk conflicting with, or unnecessarily complicating, energy infrastructure planning at other agencies. The California Energy Commission and California Public Utilities Commission both support infrastructure deployment through a variety of programs. CARB would have to consult with either or both agencies before awarding capacity-based LCFS credits, or risk interfering with, or duplicating, efforts by those other agencies. Infrastructure planning at the project level is a more appropriate for other programs outside the LCFS.

We recognize that many fueling infrastructure developers are finding it difficult to develop project capital from expected LCFS credit revenue, this problem is common throughout the alternative fuels space. We support efforts to make LCFS credits a more secure financial instrument which could back debt or equity for project capital. We support efforts to reduce policy risk, which is a main reason why financial institutions often under-value future LCFS credit revenue, and we would support efforts to address this problem in a more appropriate way, such as a State-backed green bank, loan guarantees or policy risk insurance. (NEXTGEN1_124-32a)

> **Agency Response:** Staff acknowledges that other programs are currently supporting ZEV infrastructure with various mechanisms and programs. CEC grant funding in particular has proven an effective lever, but availability of funding in future years is uncertain and is, therefore, an insufficient instrument for meeting the Governor's goals of 200 hydrogen stations and 10,000 DC Fast Chargers by 2025. The Governor's Executive Order and Board Resolution 18-17 specifically directed staff to explore ways to strengthen crediting for ZEV

infrastructure within the program. Staff included a 15-year crediting period for HRI credits and a 5 year crediting period for FCI credits, which staff believes provides sufficient incentive to encourage investment in ZEV technology.

J. Pathway Application and Carbon Intensity Determination

J-1. *Support for Amendments to the Pathway Application and Carbon Intensity Determination Provisions*

J-1.1. Multiple Comments: *Support for Design-Based Pathway Classification*

Comment: It expresses Fulcrum's strong support for the ARB proposal to include design-based pathways in the Low Carbon Fuel Standard ("LCFS") to better achieve California's greenhouse gas ("GHG") reduction goals. The specific provision referenced is a proposed new section, 17 CCR §95488.9(e).

…

Prior to the effective date of the re-adopted LCFS (December 31, 2015), low carbon fuel producers could apply for LCFS pathway approval prior to facility commissioning based on the design and engineering of the planned production facility. Such pathways were referred to as prospective pathways ("Prospective Pathways"). Subsequent to the effective date of the re-adoption (January 1, 2016), ARB ceased certifying Prospective Pathways.

Through proposed §95488.9(e), ARB has proposed to establish a new regulatory basis for Prospective Pathways. As stated in the Initial Statement of Reasons, "Staff is proposing to create a special provision to allow the Executive Officer to evaluate fuel pathways for fully engineered and designed facilities that have not yet commenced commercial production."[4] Fulcrum is strongly supportive of this proposed regulation, and is able to relate information regarding the company's direct experience regarding the importance of an ARB approved CI in the financing and development of new low carbon fuel facilities.

[4] California Air Resources Board Staff Report, Initial Statement of Reasons (ISOR) at III-05, ISOR available at https://www.arb.ca.gov/regact/2018/lcfs18/isor.pdf (release date March 6, 2018).

(FULCRUM1_103-2)

Comment: Fulcrum was successful in obtaining approval for a Prospective Pathway using the CA-GREET 1.8b model under the prior LCFS regulation. Specifically, Fulcrum obtained a pathway for Fischer-Tropsch ("FT") diesel via gasification and FT synthesis of MSW (Pathway Code: FTD 001). Subsequently, Fulcrum received notice that ARB was prepared to re-certify Fulcrum's pathway under CA-GREET 2.0 with a CI score of 14.78. Fulcrum accepted this re-certification.

ARB's approval of Fulcrum's Prospective Pathway approval and re-certification of the FTD 001 pathway has been valuable in facilitating the financing of the Sierra BioFuels Plant. Fulcrum's Prospective Pathway is highly important to investors and impacts the facility's financial projections because Fulcrum's CI score of 14.78 will provide more than $1.00 of LCFS credit value per gallon in an LCFS credit market of approximately $100 per MT.

Fulcrum's direct experience in the marketplace provides market-based evidence in support of the rationale for design-based pathways contained in the ISOR:

> *Rationale Supporting Proposed Solution*
>
> *The LCFS program seeks to incentivize the development of next-generation low-CI fuels. Investors in promising fuel production technologies seek investor support to provide long-term financing for planning, designing, building and commencing operation. Posting such Design-based pathways with a CI score based on considerations by the Executive Officer may help facilitate investments in such projects, potentially ensuring commercialization of novel fuel production technologies.*[5]
>
> [5] ISOR at III-105.

We therefore concur with staff's rationale for this provision, and support the adoption of §95488.9(e). (FULCRUM1_103-3)

Comment: Enerkem supports the creation of the new design-based pathway category to allow facilities that are not yet in commercial production to obtain a CI, which cannot be used to generate credits. This approach will enable facilities in the planning and developments stages to better assess the CI of their future products and consequently their market value. This will help facilities with low carbon fuel pathways attract investment and will have a positive impact on the availability of low carbon fuels.

…

We support the creation of the design-based pathway category…. (ENERKEM1_135-4)

> **Agency Response:** Staff appreciates the support for the proposed design-based pathway classification**.**

J-1.2. Multiple Comments: *Support for Updates to the Lookup Table Pathways*

Comment: LADWP supports the updates to the Lookup table pathway, in particular, the addition of fossil CNG and renewable electricity pathway. LADWP also supports the annual CI update to the CA Grid Electricity pathway. (LADWP1_38-9)

Comment: PG&E supports CARB's proposed changes to the Lookup Table and specifically its proposal to annually update the California grid electricity pathway to better recognize the decarbonization of the electricity sector. Establishing a single, annually updated statewide CI is preferable to sub-grid or individual source-type CIs, will provide sufficient incentive for statewide adoption of EVs, and will support clearer accounting of incremental LCFS credits from CARB's proposed zero-carbon electricity and time of use (TOU) electricity pathways. (PGE1_120-20)

Comment: *SMUD supports the updated electricity carbon intensity look up table value of 93.42 gCO2e/MJ in Table 7-1, and the stated process to update it annually.* Annual updating would reflect the rapidly evolving de-carbonization of grid electricity sources.

This is especially important as more and more marginal load is supplied by renewable resources such as photovoltaic and wind power. With the current low cost of wholesale photovoltaic power, it is becoming a first choice in all power procurement options, which should help accelerate reduction in electricity carbon intensity. (SMUD1_85-10)

Comment: 4. CalETC supports the draft regulation order's proposal for updated values to carbon intensity for statewide average grid electricity…

b. CalETC supports the new lower carbon intensity for grid electricity with annual updates.

…

4. CalETC supports the draft regulation order's proposal for updated values to carbon intensity for statewide average grid electricity…

b. CalETC supports the new lower carbon intensity for grid electricity with annual updates.

The draft regulation order proposes to update the California statewide average carbon intensity for grid electricity[2] to reflect the annual changes in California's electricity mix driven by the Renewable Portfolio Standard and other factors. The draft regulation order proposes to update the statewide average CI for grid electricity based on "CA-GREET 3.0 Look-up Table Pathways Technical Support Documentation" which references the California Energy Commission's (CEC's) analysis. In addition, the CA-GREET3.0 model inputs and data sources used to calculate the CI updates will be posted for 45 days for public comment prior to certification.

[2] See page 138 in the draft regulation order and specifically ELCG in table 7-1.

The draft regulation order proposes 93.42 g/MJ for grid electricity in California in the look-up table in Table 7-1, which better reflects the CI of California's grid-electricity mix compared to the current LCFS value of 105.16 g/MJ. Because of the impact of EERs, the effective g/MJ for grid electricity is 72 percent less than gasoline's carbon intensity and 81 percent less than diesel's.[3] Because the CI of California's electricity is expected to continue to significantly change due to the state's policies, we concur with CARB that annual updates to the CI for grid electricity are appropriate. CalETC also agrees that CEC reports are more recent and appropriate to use, as compared to the than using e-Grid data which is used in the current LCFS for the statewide-average grid-electricity carbon intensity.

[3] The effective carbon intensity in the LCFS using grid average electricity in 2019 is 27.5 g/MJ for a light-duty EV and is 18.6 g/MJ for an electric bus, electric medium-duty or heavy duty vehicle based on the new EERs and the new carbon intensity for electricity, gasoline and diesel in the draft regulation order's Table 7- 1.

(CALETC1_96-6a)

Comment: CARB staff is recommending an annually adjusted lower CI for electricity fuel. CalETC supports this recommendation. (CALETC2_130-1)

Comment: 17. CalETC supports the draft regulation order's proposal to reform the LCFS Data Management systems, and supports the draft regulation order proposal to reform Tier 2 pathways and look-up table pathways.

…

17. CalETC supports the draft regulation order's proposal to reform the LCFS Data Management systems, and supports the draft regulation order proposal to reform Tier 2 pathways and look-up table pathways. (CALETC1_96-20)

> **Agency Response:** Staff appreciates the support for the proposed changes to the Lookup Table.
>
> In response to CALETC1_96-6a and CALETC2_130-1, staff appreciates the support for the Lookup Table CI for the "California Average Grid Electricity used as a Transportation Fuel in California" pathway, which will be updated annually.
>
> In response to CALETC1_96-20, staff also appreciates support for proposed changes related to Tier 2 pathways and supporting changes in the LCFS Data Management System.

J-1.3. *Support for Offering Temporary Carbon Intensity Values*

Comment: EcoEngineers supports CARB's efforts to offer fuel pathway applicants a temporary fuel pathway carbon intensity value that the can use for reporting purposes. (ECOENGINEERS1_B5-9)

> **Agency Response:** Staff appreciates stakeholder support for offering Temporary carbon intensity values which can be used for reporting.

J-1.4. *Support for Differentiation Offered for Wet and Dry Distillers Grains*

Comment: KAAPA Ethanol would like to provide comments on the proposed regulation order for the low carbon fuel standard regarding the verification of carbon intensity for corn ethanol plants. First, we thank the ARB for including many provisions that will enable the recognition of lower carbon intensity for ethanol to California. Among these is the opportunity to develop separate pathways for wet and dry distillers grains (DGS) ethanol. These pathways are important because ethanol plants may encounter swings in the amount of drying of the co-product distillers grains depending on weather, operating, and marketing conditions. (KAPPA1_74-1)

> **Agency Response:** Staff appreciates support for the differentiation offered for wet and dry distillers grains produced during the starch ethanol production process.

J-1.5. Multiple Comments: *Support for Starch and Fiber Ethanol Carbon Intensity Calculations*

Comment: A. Expeditious approval of new pathway petitions for cellulosic ethanol produced from grain kernel fiber

RFA applauds CARB's expeditious approval of recent pathway petitions for the production of cellulosic ethanol from corn kernel fiber, and we encourage the Agency to act swiftly on pending and upcoming pathway petitions. Dozens of existing corn ethanol plants have adopted, or are in the process of adopting, new technologies that enable the low-cost production of low-carbon ethanol from the cellulosic fibers found in the corn kernel. If adopted broadly across the industry, these technologies could result in the production of 500 million to 1 billion gallons of low carbon ethanol, much of which may be available to the California market. (RFA1_80-1d)

Comment: CARB is proposing a number of important changes to the fuel pathway application process and determination of carbon intensity (CI) values. In general, we appreciate the efforts undertaken by CARB staff to further streamline and simplify the tools used for determining CI values. (RFA1_80-5)

Comment: We are pleased that CARB has added the capability to separately account for denatured and undenatured ethanol production. Because denaturant can have considerable effects on the overall pathway CI, it is appropriate for the calculator to account for only the actual amount of denaturant used for denatured fuel ethanol. (RFA1_80-6)

Comment: We support CARB's requirement that "beginning corn inventory" be recorded in bushels with *15% standard moisture included* and "not to be reported on a dry basis." Additionally, we agree with CARB's decision to allow alternate approaches to recording corn inventory only if the applicant provides all appropriate conversion factors to CARB. This will eliminate potential errors and uncertainties regarding ethanol yield per bushel. (RFA1_80-7)

Comment: Specifically, POET is glad to see that CARB is updating aspects of its scientific assessment of corn starch ethanol carbon intensity values ("CIs"), and that the updates move corn starch ethanol CIs closer to the value that POET believes is best supported by the most current scientific data. (POET2_B3-2)

Comment: The simplified starch calculator that CARB released as part of the rule making process on March 6, 2018 appears to be functioning properly. The incorrect N_2O emission factor for corn that was presented in the version released in November has been corrected.

We were able to confirm that all of the emission factors used in the calculator came from the CA GREET 3.0 model. (GROWTHENERGY1_B4-109)

> **Agency Response:** Staff appreciates support for CARB's approval of recent pathway applications for the production of cellulosic ethanol from corn kernel

fiber. Staff will act in the process outlined by the regulation to assess all pathway applications, including pending and upcoming pathway petitions for cellulosic ethanol.

Staff also appreciates the support offered to the process to streamline and simplify the tools used for CI determination, the support for the provision offered to distinguish between undenatured and denatured ethanol production at a starch ethanol plant, and the support for the aforementioned requirements to account for corn inventory at a starch ethanol plant.

Staff also appreciates support for updates related to corn starch ethanol, and appreciates feedback related to the starch Simplified CI Calculator.

J-1.6. *Support for Sugarcane Ethanol Carbon Intensity Calculations*

Comment: We commend CARB for its efforts to simplify and make the LCFS registration process more efficient. We also appreciate the opportunity to have an open channel of communication with staff involved in this process. (UNICA1_127-6, UNICA2_B2-6)

Agency Response: Staff appreciates support for simplicity and efficiency of the LCFS registration process. The entire regulatory process has included open channels of communication with all stakeholders and staff appreciates the acknowledgement.

J-2. *CA-GREET3.0 Model*

J-2.1. *Data Source for Electricity Mixes*

Comment: While CA-GREET2.0 uses USEPA's eGrid as a source of electricity mix for both stationary and transportation uses, CA-GREET3.0 uses the eGrid as a source of mix for the stationary uses and the California Energy Commission report as a source of electricity mix for transportation uses. WSPA requests that ARB provide the justification of the change and the rationale to use different mixes for stationary and transportation uses. As mentioned in the same document, determining a marginal mix is highly speculative. (WSPA2_61-29)

Agency Response: As with previous CA-GREET model versions, CA-GREET3.0 uses the electricity mix provided by the U.S. EPA's eGRID2014v2 (data year 2014) to provide a consistent source of data for all energy input for comparable domestic transportation fuel pathways across all U.S. regions. The LCA methodology used in determining the average emissions associated with the use of electricity is the same for both stationary and transportation processes. As explained in the staff report, the amendment proposal to use a more recent and accurate data source to more accurately reflect California's rapidly transforming electricity mix for purposes of electricity fueling pathways certified by the LCFS is designed to "incentivize emission reduction through transportation

electrification by more accurately reflecting the decreasing carbon intensity of the California electricity grid."

CEC updates the Quarterly Fuel and Energy Report roughly 6 to 7 months after each data year, whereas updates to the eGRID dataset are typically published two to three years after each data year. Staff believes that CEC's data is the best source available reflecting the electricity used to fuel EVs in California by providing a more current representation of the decreasing carbon intensity of the California electricity grid. As proposed, use of this data source in this application is not speculative.

J-2.2. Multiple Comments: *Distiller's Grains Methane Credit*

Comment: ARB made the corn ethanol emissions in CaGREET3.0 to be mostly consistent with the GREET2016 model. We have two comments on this update:
(1) staff did not include the distillers' grains methane credit in GREET2016…
(GROWTHENERGY1_B4-103)

Comment: In addition to ethanol, all dry mill ethanol plants produce distillers' grains, which are fed to livestock. The distillers' grain can either be wet (used immediately), or it can be dried and used later. Beef cattle that are fed distillers grain (either wet or dry) have reduced enteric fermentation as compared to cattle that are not fed this product, and the result is lower methane emissions overall from cattle. Methane is a greenhouse gas. The emission credit from reduced methane emissions from cattle is called the DDG methane avoidance credit.

GREET2016 contains distillers' grains (DDG) methane avoidance credit. The credit is 2.1 g/MJ, which is sufficient to have a material effect on the CI of an applicant's pathway. ARB's rationale for not including this credit is stated in its report on CaGREET2.0.

> There is no credit for reduced enteric fermentation emissions due to the inclusion of DGS in livestock rations in LCFS ethanol pathways. The animals consuming the DGS are not currently in the LCFS LCA ethanol system boundary.[1]
>
> [1] *CA-GREET 2.0 Supplemental Document and Tables of Changes, ARB Staff Update, June 4, 2015, page 49.*

This stated reason for not including the DGS methane avoidance credit is inconsistent with ARB's granting of a LCFS pathway for methane produced from livestock manure, in which case the pathway was allowed a substantial credit for methane avoidance similar to the methane avoidance credit for DGS.[2] If ARB allows a methane avoidance credit for methane produced from manure, ARB should allow a methane avoidance credit for corn ethanol from DGS use as well.

[2] Pathway T2R-1062, Fuel Producer: California Bioenergy LLC (B194) Facility Name: Kern County Dairy Biogas Cluster (B2139), Dairy Biogas from Kern County from dairy manure covered anaerobic lagoons to CNG in California (accounting for avoided methane per ARB Livestock Offset Protocol), https://www.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm. Pathway CI is -272.97 for the LCFS.

CARB staff's decision to not provide a DDG methane avoidance credit is also inconsistent with ISO life cycle assessment (LCA) standards. The LCA concept emerged in the late 1980's from competition among manufacturers attempting to persuade users about the superiority of one product choice over another. As more comparative studies were released with conflicting claims, it became evident that different approaches were being taken related to the key elements in the LCA analysis:

- Boundary conditions (the "reach" or "extent" of the product system);
- Data sources (actual vs. modeled); and
- Definition of the functional unit.

In order to address these issues and to standardize LCA methodologies and streamline the international marketplace, the International Standards Organization (ISO) developed a series of international LCA standards, specifications, and technical reports under its ISO 14000 Environmental Management series. The main contribution of these ISO standards was the establishment of the LCA framework that addressed the inconsistencies and allowed for proper comparisons between products or systems.

CARB staffs decision to not provide a DDG methane avoidance credit is also inconsistent with ISO LCA standards. In CARB's approach, the lifecycle system boundary includes the production and use of corn ethanol but only the production of the DDG. This approach is inconsistent with the ISO LCA standard 14044, which states:

> LCA addresses the environmental aspects and potential environmental impacts (e.g. use of resources and environmental consequences of releases) throughout a product's life cycle from raw material acquisition through production, use, end-of-life treatment, recycling, and final disposal (i.e. cradle-to-grave).[3]
>
> [3] https://www.iso.org/obp/ui/#iso:std:iso:14044:ed-1:v1:en

CARB have deviated from international norms by effectively truncating the system boundary so as to exclude the emission benefits of the use of DDG compared to other animal feeds. (GROWTHENERGY1_B4-105)

> **Agency Response:** Please see the response to comment GROWTHENERGY1_B4-23a in the Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.
>
> In addition, staff adds the following points:
>
> The methane emissions impact of feeding DDG can vary based on animal type, age, lactation status (for dairy cows), and can even potentially change based on other components and additives in the animal's diet. Staff believes there is a lack of established research that conclusively determines the effectiveness of methane emissions reductions when DDG is fed to cows.

The total mixed ration for cattle is also variable throughout the course of a year, and depends largely on availability and cost. Due to this inherent lack of consistency within the feed system, it is difficult to say with certainty that cattle are fed DDG all year long. In addition, lack of clarity as to the baseline diet for cattle under consideration presents another challenge to attributing enteric methane emissions reductions to a fuel pathway.

J-2.3. Multiple Comments: *Carbon Intensity Calculation of RNG as a Processing Fuel*

Comment: 3. In RNG tab, Cell F594, comment by CARB "CO2 from RNG usage is zeroed due to baseline use of LFG to NG". This means the CO2 emissions from RNG combustion are biogenic and are cancelled out by the CO2 absorbed into biomass. However, in EtOH tab, Cells S525 to S529, to calculate the emissions related to biomethane, emission factors of NG in "EF" tab are used. In EF tab, Cells B16 to H16, the CO2 from NG is about 59,000 g/mmbtu. As a result, these CO2 emissions are double-counted. The values in Cells B16 to H16 should be 0, or close to 0 for RNG. (POET1_129-7)

Comment: We are looking to implement an anaerobic digester at our facility to then produce ethanol using that gas source rather than natural gas, but we would like to estimate the CI saving of doing this project. To do this I ran our ethanol data in GREET 3.0 to find the CI from natural gas then ran it again using only renewable natural gas, however, GREET 3.0 is showing significantly higher GHG emissions from renewable natural gas compared to natural gas.

The difference I found was mainly in the CO2 calculation for the natural gas and biogas, where the highlighted cells are the main contributors to the difference in the EtOH tab:

Renewable Natural Gas:

S529=(L$435*(D$398*EF!$G16+D$399*EF!$D16+D$400*EF!$B16+D$401*EF!$C16+**RNG!E627**))/1000000

Where:**RNG!E627=46,991**

Giving a total CI for the biomethane to be **71.25** if I assumed 50,000 Btu/gal just for an example

Natural Gas:

O529=L$430*(D$398*EF!$G16+D$399*EF!$D16+D$400*EF!$B16+D$401*EF!$C16+**NG!$B101**)/1000000

Where: **NG!B101=6,916**

Giving a total CI for the biomethane to be **45.7** if I assumed 50,000 Btu/gal just for an example

I know biomethane shouldn't really have GHG emissions that are roughly twice the fossil fuel equivalent, so I am curious why the RNG option is so high. (GEVO1_138-1)

> **Agency Response:** When renewable natural gas (RNG) is used as a process fuel in a fuel production facility, there are no attributable CO_2 emissions from combustion of RNG. This has been corrected in CA-GREET3.0.

J-2.4. *Technical Comments in Previous Letter*

Comment: Additionally, our technical comments to the GREET 3.0 model, which have not been fully addressed, are included in in our previous comment letter (attached). (SCG1_75-2)

> **Agency Response:** Please refer to Responses J-2.14 J-10.3,J-10.9, J-10.4, and U-2 in this chapter.

J-2.5. *Energy Density for Propane*

Comment: This is minor and quite possibly nitpicky, but I'm getting some of our rulemaking stuff together and noticed that the energy density for propane in table 4 – 88.89 – is lower than what's in the GREET 3.0 Fuel Specs tab. Using the MJ2BTU conversion, I get 89.63 for LPG/Propane and I'm not seeing anything in the ISOR or GREET 3.0 documentation for why the 88.89 number was picked. Is it a product of the 25/75 ratio of natural gas versus crude sources of LPG?

	A	B	C	D	E	F	G	H	I	J
34	Acetone	83,127	83,127	89,511	2,964	62.0%	0	0.000000	0.929	
35	E-Diesel Additives	116,090	116,090	124,340	2,819	86.3%	26	0.000026	0.934	
36	Liquefied petroleum gas (LPG)	84,950	84,950	91,410	1,923	82.0%	0	0.000000	0.929	89.63
37	Liquefied natural gas (LNG)	74,720	74,720	84,820	1,621	75.0%	0	0.000000	0.881	78.83

(ODOEQ1_141-1)

> **Agency Response:** Staff has corrected the energy density of propane in Table 4 to reflect LHV of LPG (89.63 MJ/gal).

J-2.6. *Broken Links*

Comment: 1. Inputs tab has several broken links to the ETOH tab (POET1_129-5)

> **Agency Response:** Any broken links identified have been fixed by staff. Please see Response J-2.3 in this chapter for the only specific comment regarding a broken link in the EtOH tab of CA-GREET3.0.

J-2.7. *Emission Factors in CA-GREET3.0*

Comment: Most of the emission factors in starch sheet are in the ballpark but do not exactly match the factos [*sic*] in CA_GREET3 (GR3) to decimal places. They should be recalculated and pasted again to accurately replicate the results from GR3. We have pasted the EF we calculated from GR3 in the starch sheet for your reference. We have

also marked these EF calculations in the attached GR3 in blue to demonstrate the calculation these and allow quick replication for regions/model versions.

- In the GR3, our calculations are marked in light blue. The EF calculations are located on the respective sheets. For example, we have calculated the
  - electricity EF on electric sheet,
  - NG EF on NG sheet,
  - soy oil EF on BioOil sheet,
  - corn farming EF on EtOH sheet next to farming calculations,
  - corn and EtOH transportation calculation next to the calculation summary at bottom of EtOH sheet etc. (LCA1_8-4)

Agency Response: Staff has reviewed the emission factors in the starch calculator and compared them to the CA-GREET3.0 model and concluded that all emission factors in the starch calculator match the values in the CA-GREET3.0 model.

J-2.8. *Emission Factors of Coke Combustion*

Comment: For FCC coke combustion in the petroleum tab of GREET2016, ANL used the emission factors of petcoke (101.64 g CO_2e/MJ). In ANL-GREET 2017, ANL added the emission factors of FCC coke combustion (96.21 g CO_2e/MJ). It is recommended that ARB use the newly added emission factors of FCC coke combustion. (WSPA2_61-28)

Agency Response: The CA-GREET3.0 model is based on Argonne's GREET 1_2016 version and uses the same value for petcoke (101.64 gCO_2e/MJ). The value being cited by the commenter refers to 'catalyst coke', an addition to Argonne's 2017 version and is, therefore, not relevant to the proposed amendments.

J-2.9. *Refining Inputs*

Comment: In addition, it is requested that ARB provide a calibration verification showing how the share of energy inputs in Tables A.5 for CARBOB refining and B.4 for ULSD refining correlates with the fuel use data published by the Energy Information Administration (EIA). Further, the source of the purchased hydrogen data should be cited in the document. (WSPA2_61-31)

Agency Response: Argonne's LP modeling results using proprietary data from refineries in California is used to estimate refinery efficiency with corresponding energy inputs as reported in Tables A.5 and B.4 for CARBOB and ULSD, respectively. Since the modeling uses proprietary data, Argonne has not shared any data related to refinery modeling in the GREET model. Hydrogen used in

refinery processing has also not be provided by Argonne due to tagging of all data shared with Argonne being deemed business confidential.

J-2.10. *Providing CA-GREET Model with User-Defined Tier 2 Pathway Section*

Comment: In the CA-GREET 2.0 model, an applicant can create user defined Tier 2 pathways in various tabs (such as EtOH and BioOil). The user defined Tier 2 pathway section has been eliminated in the proposed version of the CA-GREET 3.0 model. WSPA requests that ARB provide an updated CA-GREET 3.0 spreadsheet model enabling user defined Tier 2 pathways without having applicants overwrite existing cells in the model. (WSPA2_61-32)

> **Agency Response:** A few standard templates or modifiable tabs have not be included in CA-GREET3.0 to model potential Tier 2 pathways given the inherent complexities of life cycle analysis of such pathways. Staff, therefore, did not include specific tabs or templates to accommodate user-defined Tier 2 pathways in CA-GREET3.0. Staff is available to work with stakeholders to develop such templates to reflect individual fuel pathway processes including facilitating verification with the development of such templates. Individual cells highlighted in yellow reflect user-defined values which are based on operational data or specific to a given production process developed in consultation with staff.

J-2.11. *Sulfur Content in Diesel*

Comment: Under the "Fuel_Specs" tab, the sulfur content in conventional diesel and California diesel should not exceed 15 ppm post-2005. The model shows 200 ppm and 120 ppm respectively. It is requested that the document be revised to correct the specifications and report impact to CI values, if any. (WSPA2_61-33)

> **Agency Response:** To avoid confusion, staff deleted the "California diesel" entry listed in the "Fuel_Specs" tab as it contains high sulfur diesel, which is not used in CA-GREET3.0. The CA-GREET3.0 model uses fuel properties of "Low-sulfur diesel" (sulfur content at 11 ppm) for ULSD. On the other hand, staff did not revise the properties of the "U.S. conventional diesel" referred in the comment, as it represents conventional diesel used in many fuel production-related activities outside of California, such as feedstock farming (including off-road vehicles and machineries), chemical production, and mining.

J-2.12. *Carbon Intensity of Propane*

Comment: We wish to express our concern, however, with CARB's characterization of key parameters affecting net credit generation in the early years of participation in the LCFS.

…

I. Propane CI Should Be Decreased to Reflect Greater Proportion of Natural Gas Liquid Feedstock

The CI for propane from oil refineries varies depending upon the approach used to define the allocation of emissions within oil refineries as described in a recent study published by the WPGA[2]. The average CI of propane from oil refinery and natural gas resources is 82.37 (g CO_2e/MJ), yet CARB appears now to rely on a CI of 83.38 in Table 7-1 (Lookup Table for Gasoline and Diesel Substitutes) of the proposed regulation order.

[2] Unnasch, S. and L. Goyal (2017) Life Cycle Analysis of LPG Transportation Fuels under the Californian LCFS. Life Cycle Associates Report LCA.8103.177.2017, prepared for the Western Propane Gas Association.

While we appreciate the nuances of sources of LPG that went into ARB's analysis, the incremental nature of propane vehicle populations tied to growth of natural gas liquids should take precedence. Oil refinery capacity in California is essentially fixed and is not expected to increase, and thus growth in the use of propane will be met not by traditional petroleum refinery product but by greater quantities of natural gas-based propane. Because natural gas-derived propane has a lower CI, we urge ARB to establish a CI for fossil propane that reflects the practical, greater proportional mix of natural gas-based production. (WPGA1_121-2)

Agency Response: The LCFS analysis for CI of propane used as a transportation fuel in California considers the source of propane to be a mix of 75 percent from in-state refineries and 25 percent from natural gas sources. This is supported by:

(a) Data from the Energy Information Administration (EIA) indicate that in PADD 5, 25 percent of propane is produced from natural gas sources and 75 percent from refineries. Also, propane produced in the PADD 5 region exceeds propane used in California for all uses.[36]

(b) In 2015, about 20 percent of the odorized propane produced in California was from gas processing plants and about 80 percent was from refineries.[37]

At this time, staff is not revising the analysis for a CI for propane included in the Lookup Table. If fuel suppliers sourcing propane from specific sources can provide evidence supporting their specific resource mix, staff will consider certification of dedicated propane pathways subject to substantiality requirements stated in the regulation.

[36] U.S. Energy Information Administration. Petroleum & Other Liquids, Supply and Disposition, West Coast (PADD 5), Annual 2014, accessed Oct. 2017. https://www.eia.gov/dnav/pet/pet_sum_snd_d_r50_mbbl_a_cur-3.htm

[37] ICF. Impact of the U.S. Consumer Propane Industry on U.S. and State Economies in 2015. Prepared for the Propane Education & Research Council (PERC). September, 2017. http://www.npga.org/wp-content/uploads/2018/02/2015-Propane-Industry-Impact-on-US-and-State-Economies-FINAL.pdf

J-2.13. *Incorporating Components of Argonne GREET2016 Model*

Comment: In connection with its consideration of the amendments to the LCFS regulation, ARB has developed a new model, CaGREET3.0, to determine the carbon intensity ("CI") of various regulated fuels. To develop the new model, CARB adapted most of the Argonne GREET2016 model. We support this method in general; that is, that the California GREET model should be consistent with the latest Argonne GREET model and data for corn farming and other factors. We are concerned, however, that CARB did not incorporate some important components of the Argonne GREET2016 model, and that certain aspects of the CaGREET3.0 model are not supported by the evidence. (GROWTHENERGY1_B4-102)

> **Agency Response:** Staff modified the CA-GREET3.0 and all Simplified CI Calculators to address relevant public comments. Please see Responses J-2.2, J-2.16, J-2.17, J-5.2, J-5.3, and J-5.5 in this chapter to address concerns intended by comment GROWTHENERGY1_B4-102.

J-2.14. *Carbon Intensity Scores of Biogas Pathways*

Comment: With respect to biogas pathways, the differences between GREET 1.8b, GREET 2.0, and GREET 3.0 have been significant. Over a short three year time frame, biogas CIs have been subject to changes of 50% or more due to changing methodologies and assumptions in the GREET model. Given the volatility in the GREET model over the years, it would make the most sense to avoid annual CI verifications as it is likely that another significant change can come in the next release of the GREET model which would render previous model assumptions and annual "verification" against these assumptions moot. (SCG1_75-8)

> **Agency Response:** Staff acknowledges changes in CI scores of biogas pathways in transitioning from GREET1.8b to GREET3.0. These are mainly due to changes in accounting methods and revisions of assumptions and are natural outcomes as the science evolves and more data become available. Annual verification of a pathway CI for a particular year will be conducted using the same model used to certify the CI prior to verification. Hence, differences in assumptions and methodologies from model updates and the frequency of updates is not expected to be a challenge for fuel pathway applicants in generating and verifying credits.

J-2.15. *Reference Date on Tier 1 Calculators*

Comment: In § 95488.3(b), the Tier 1 calculators should reference March 6, 2018, rather than March 6, 2017. (WSPA2_61-18)

> **Agency Response:** Staff has updated release date to reflect the final version of all Tier 1 Calculators.

J-2.16. *Supporting Information for Refining Capacity*

Comment: In the CA-GREET 3.0 Lookup Table Pathways – Technical Support Documentation Section A (CARBOB) and Section B (ULSD), WSPA requests that ARB provide the supporting information for refining capacity, including downstream units, used in the Argonne National Lab (ANL) Linear Programming model to represent California refineries. (WSPA2_61-26)

> **Agency Response:** Argonne National Laboratory utilized proprietary California refinery data to perform LP analysis the results were shared with staff to develop baseline CIs for CARBOB and ULSD. Argonne has Nondisclosure Agreements with all participants who provided facility-specific data (such as refining capacity) and is not able to publically release data used in the LP modeling (in Argonne's publication, it is indicated that all participants "have an individual capacity of greater than 100,000 bbl/day").[38]

J-2.17. Multiple Comments: *Trucking Transport Emissions*

Comment: …the emissions for medium and heavy-duty trucks appear to be out-of-date. (GROWTHENERGY1_B4-104)

Comment: Table 1 shows the fuel economy and energy consumption of medium-heavy and heavy-heavy duty diesel trucks in CaGREET3.0.

Table 1. Energy Consumption of MHDT and HHDT Trucks in CaGREET3.0

Truck Type	Fuel economy (mpg)	Energy Consumption (Btu/mile)	BTU/ton
HHDT	5.3	24,236	1,616
MHDT	10.4	12,351	1,544

As shown in Table 1, the energy use for HHDTs is higher than for MHDTs. In CaGREET3.0, it is not logical that the energy use per ton-mile is lower for a medium duty truck than it is for a heavy-duty truck. CaGREET3.0 overestimates the fuel use for a heavy-duty truck and underestimated the fuel use for a medium duty truck compared to the most recent values in the Oakridge National Laboratories Transportation Energy Use Data Book (see Table 2).[4]

[4] Transportation Energy Data Book. https://cta.ornl.gov/data/index.shtml

[38] Forman GS, Divita VB, Han J, Cai H, Elgowainy A, Wang M. 2014. U.S. Refinery Efficiency: Impacts Analysis and Implications for Fuel Carbon Policy Implementation. Environmental Science & Technology. 48, 7625-7633

Table 2. Trucking Fuel Economies in CaGREET3.0		
Vehicle Type	CA GREET (mpg)	Transportation Energy Use Data Book (mpg)
MDT	10.4	7.4
HDT	5.3	5.9

In addition to the energy use being questionable, the load size is too small for the heavy-duty truck at only 15 tons. While the maximum load size will vary by state a typical value is 20 tons for a heavy-duty truck.

Table 3 shows the impact of making changes fin the fuel economies for MHDTs and HHDTs, and also a change in load size for HHDTs from 15 to 20 tons.

Table 3. Impacts of Fuel Economy Change and Load Size Change on Corn Feedstock Production	
Case	Feedstock Production CI (g/MJ)
CaGREET3.0 Default	17.33
Updated fuel economies (see Table 2)	17.31
Updated fuel economy and load change	17.04

Furthermore using the same energy per ton-mile for the delivery as the return trip (backhaul) is not appropriate as the load is on the order of 50%. The impact of all of the transportation issues is that the transport emissions are overstated. (GROWTHENERGY1_B4-106)

> **Agency Response:** After consulting with Argonne's GREET team, staff updated fuel economy for medium- and heavy-duty trucks (both forward and backhaul trips) as well as truck payload for transport of corn, soybean and canola. The CA-GREET3.0 supplemental document provides details of the updated values.

J-2.18. *Transition to CA-GREET3.0*

J-2.18a. Comment: REG looks forward to start updating of all of its fuel pathways under CA-GREET 3.0. We hope that we are able to start using them during 2019 though it appears that there could be a significant rush of new FPCs come January 1, 2020. We suggest that CARB have a transition period to help avoid overloading CARB staff with hundreds of simultaneous requests. (REG1_88-21)

> **Agency Response:** All applications received starting January 1, 2019 will be prioritized on based on submission date. Although there is a possibility for significant number of applications to be submitted in early 2019, the provision to sunset pathways certified using CA-GREET2.0 at the end of the calendar year 2020 will offer flexibility for applicants to continue to report fuel transactions using previously approved FPCs. The availability of temporary CIs is another option available to new applicants if there are delays due to significant pathway applications in early 2019.

J-2.18b. Comment: We request additional clarity on the transition to GREET 3.0. A timeline that demonstrates when a fuel pathway applicant can use GREET 2.0 versus 3.0 and CARB's review and approval plan for each will be useful. For example, will CA-GREET 2.0 pathway applications pending as of 1/1/2019 continue to be reviewed and certified into 2019, or will applications in the queue be rejected? (ECOENGINEERS1_B5-6)

> **Agency Response:** The use of CA-GREET2.0 is permitted for pathway applications received through December 31, 2018. Staff will commit to certifying as many applications received through the end of 2018. Pathway applications not certified in 2018 will be deleted. Applicants will be required to submit new applications using CA-GREET3.0 based life cycle analysis and will be subject to all requirements of the updated LCFS regulation.

J-2.18c. Comment: 5. Section 95488(c) – Transition to CA-GREET3.0 is Unduly Burdensome

Kern urges ARB to reconsider the proposed requirement under 95488(c) that fuel pathway holders reapply for pathway certification using the updated CA-GREET3.0 model to have a valid fuel pathway for use in 2021 and beyond. Kern recognizes and appreciates that ARB's proposed approach to transitioning from pathways certified under CA-GREET2.0 now includes an additional year to transition existing fuel pathways. However, requiring fuel pathway holders to reapply, subject to the full pathway application and certification process again is also unnecessarily rigorous. Kern urges ARB to work with stakeholders to develop a transitional approach for integrating CA-GREET 3.0 with pathways recently certified using CA-GREET 2.0 in lieu of full reapplication.

Fuel pathway applicants today are required to use CA-GREET2.0 to model the life cycle emissions and determine the carbon intensity of their fuel. Tier 2 pathway applications largely require the use of site-specific data in determining the appropriate input values for various parameters required by the model. The process for collecting and evaluating the site-specific data in support of these unique inputs is an arduous task, but results in a defensible and verifiable fuel pathway. At the September 22, 2017, workshop, ARB Staff verbalized that transitioning to CA-GREET3.0 certified pathways will not be “as simple as plugging CA-GREET2.0 inputs into the CA-GREET3.0 model.” In actuality, the process should be just that easy. A certified fuel pathway holder has already made the required demonstrations for data integrity, such that the full application analysis is unnecessary, particularly in light of the proposed verification process.

The proposed third-party verification process includes provisions for a pathway holder to adjust the pathway CI if the verification determines an operational CI lower than the certified CI. Kern believes ARB could employ a similar strategy to provisions for transitioning from CA-GREET 2.0 to CA-GREET 3.0. That is, for pathways certified within 2018 and 2019, the transition could consist of a validation-type process, where the difference in CI would be attributed to difference in the models and the certified CI could be adjusted accordingly.

Kern has invested a more than a year of work and a significant amount of money into the process for fuel pathway certification, and at this time expects to receive a certified CI in the third quarter 2018. Kern would only be able to use the certified CI for generating credits during the remainder of calendar year 2018 through 2020, after which this fuel pathway would be deactivated. Under ARB's current proposal, Kern would need to begin the lifecycle analysis by mid-2019 in order to work through the approval process and receive a new certified CI using GREET3.0 by 2020. The current proposal would further require Kern to hire an approved third party to perform the pathway validation process, making the reapplication process even more costly. This duplication of efforts is a waste of financial resources and an inefficient use of staffs time, especially for a small refinery. Kern is concerned that this requirement puts up barriers for small producers to get renewable fuels into the market with very little benefit to ARB. (KERN1_115-5)

Agency Response: Staff do not agree with the commenter that the transition to the new model should follow a similar process used during transition from CA-GREET1.8b to CA-GREET2.0. The amendments offer a full two years for pathways certified under CA-GREET2.0 to utilize CA-GREET3.0 which should be adequate to transition to the new requirements.

Fuel pathways certified under CA-GREET2.0 have until December 31, 2020 to continue to use the existing certified CI for reporting transactions in the LCFS. Staff believes that this flexibility provides stakeholders ample time to transition to the updated regulatory requirements using CA-GREET3.0. It is quite likely that the commenter misinterpreted verbalization at the September 22, 2017 workshop about challenges transitioning from CA-GREET2.0 to CA-GREET3.0. As expressed by the commenter, transition to the new model is not expected to be daunting even for complex Tier 2 pathways. This is because the life cycle approach is expected to be the same or similar to CA-GREET2.0. Only relevant site-specific inputs for production parameters will be required to be transferred to the Simplified CI Calculators or CA-GREET3.0 model (for Tier 2 pathways) and CIs will be calculated using standard parameter values and emission factors.

For the amendments to the LCFS, staff is mandating third-party review of substantiating documentation and calculations for fuel pathway applications, including recertification of existing fuel pathways, which will provide reasonable assurance of data and CI accuracy. Third-party validation of existing pathways that are updated to CA-GREET3.0 will ensure accuracy and consistency among existing and new pathways moving forward. As for concerns related to financial costs for third-party verification, the revenue generated from LCFS credits are expected to far outweigh costs related to verification and will support a greater confidence in the LCFS market overall. In addition, staff proposed a threshold for eligibility for deferring verification up to two years for small alternative fuel producers in section 95500. See Response O-5 in this chapter regarding verification costs and eligibility to defer verification.

J-2.18d. Multiple Comments: ***U.S. Average Electricity for Transportation and Distribution***

Comment: The ethanol (and even other finished fuels) transportation EF in the starch sheet are currently based on US average region. However, changing these EF to match CA specific diesel should be considered as that will be the most likely case. You can also consider adding a note on the rail vs truck distance that they are an either-or case. meaning, that a plant will typically deliver its fuel to bulk terminal by EITHER rail OR truck, not both. (LCA1_8-6)

Comment: There is one small issue with the emission factors for ethanol transportation. In GREET there is a small amount of electricity that is used in the transportation and distribution calculations that is independent of the mode of transport. This is essentially the power to load the truck or rail car. The emissions for the power are determined by the region used for the electric power mix. For starch ethanol most of the trucking emissions are likely to be in California but the emission factor is developed using US average power. The value used is 0.6366 g CO_2eq/gal-mile. The California value is 0.6287 g CO_2eq/gal-mil. The difference is small but as shown below the lower value is being used for sugarcane ethanol. (GROWTHENERGY1_B4-110a).

> **Agency Response:** Differentiating regional transport emissions for freight transport outside California presents a significant burden, given the likelihood of a single batch of freight traveling through multiple states/regions. Staff has, therefore, elected to use a U.S. average emission factor for freight transport for all states in the United States except for California. Emissions from freight transport are likely to be different within the state compared to other states in the union given the stringent fuel specifications and emission factors.
>
> In relation to finished fuel transportation, the instruction manual for starch ethanol calculator states, “For transport of finished fuel to California, applicants must input the appropriate transport distance by Heavy-Duty Diesel (HDD) truck and rail transport as applicable.” Emissions from transport modes are additive to reflect all legs of transport of finished fuel to California. If a plant uses only rail or truck to deliver fuel, only the relevant mode of transport should be included in the life cycle analysis in the fuel pathway application.
>
> Note: For applicants who expect to use various combinations of transport modes to ship fuel to California, staff suggests calculating CIs for each combination and inputting the combination with the highest CI in the Simplified CI Calculator, to prevent unintentional exceedance of the pathway CI. The supplementary documentation provided with the application must include the CIs for each of the anticipated combinations and highlight the combination used in the Calculator.

J-2.18e. Comment:

1. Applicants who use corn kernel fiber technology will be able to complete a Tier 1 pathway, correct? If so, is this only for the Edeniq process?

2. In the simplified ethanol calculator it has a section for electricity for solar or wind. In the instructions it states that it must meet the requirements of 95488.7(i). I am not finding that citation in the new LCFS. It states from wind or solar, but what it is a steam turbine operating off of their existing steam unit? Is this able to be accomplished in a Tier 1 application?
3. Previously Tier 1 applications were treated as confidential automatically. For the new LCFS, will they needed to submitted with a confidentiality claim or does the auto-confidentiality still apply?
4. Lastly, as part of the Tier 1 application section it states you can provide supplemental information if you are using an alternative form of process energy – is this if they are using a dedicated turbine or something of that nature? I just want to make sure if that is the case, then Tier 1 ethanol plants are about to continue with a Tier 1 process if they have a turbine. (ERI1_6-1)

Agency Response: The responses to questions 1-4 are as follows in the same order.

1. Please see Response J-4.2 in this chapter.
2. This particular reference to 95488.7(i) is incorrect in the version of Appendix A released on March 6, 2018; it should instead read 95488.8(i). Other electricity options may require the use of a Tier 2 framework.
3. Staff will continue to treat all data and other information provided as part of a Tier 1 pathway application as confidential (the same applies also to a Tier 2 application).
4. Depending on the specifics of turbine operation, a fuel pathway application can either be modeled as a Tier 1 or a Tier 2 pathway.

J-3. Refining Efficiency

J-3.1. Comment: The refining efficiency of CARBOB is lower than those in GREET 2016 (as well as GREET 2017). ANL-GREET's value is 88.74% while CA-GREET 3.0's value is 88.64%. WSPA requests that ARB provide rationale for the difference.

ANL included CA ULSD in its GREET 2017. The efficiency of CA ULSD in CA-GREET 3.0 is lower than those in GREET 2017. ANL-GREET's value is 85.98% while CA-GREET 3.0's value is 85.87%. WSPA requests that ARB provide rationale for the difference. (WSPA2_61-27)

Agency Response: Argonne's GREET model (both 2016 and 2017 versions) uses 2015 as the baseline year, whereas CARB's CA-GREET3.0 uses 2010 as the baseline year for petroleum refineries. In other words, the 88.74 percent (CARBOB) and the 85.98 percent (ULSD) listed in the comment are based on the 2015 scenario, whereas the 88.65 percent (CARBOB) and the 85.87 percent (ULSD) are based on the 2010 scenario.

J-3.2. Comment: Table A.5 compares the CARBOB's CI between CA-GREET2.0 and CA-GREET3.0. The efficiency changes from 89.00% to 88.64%. With 89.00% efficiency, the energy loss to produce 1MJ of gasoline is 0.1236 MJ (=1/0.89-1). Similarly, with 88.64% efficiency, the energy loss to produce 1 MJ of gasoline is 0.1282 MJ (=1/0.8864 – 1). So, the energy loss increases by 3.7%. On the other hand, the CI of refining increases 13.45 to 14.92 g CO_2e/MJ by 10.9%. Unless there are major changes in process fuel shares, the changes in CI follow the changes in energy loss. WSPA requests that ARB provide the explanation for the larger CI changes relative to the energy loss changes. (WSPA2_61-30)

Agency Response: (1) In CA-GREET2.0, the refining efficiencies of various products were based on the Linear Programming (LP) modeling results for PADD V. In CA-GREET3.0, these efficiencies are based on California-specific refineries. (2) The LP model analysis facilitated attribution of specific refinery efficiency and process energy shares to each individual finished refined product. Earlier versions of GREET used an aggregated approach to estimate refining efficiency and process shares to individual refined products. Due to this refinement in refinery modeling, share of process energy inputs for CARBOB and ULSD are different in CA-GREET3.0 consequently leading to different CIs for CARBOB and ULSD in the current analysis. The following table summarizes the differences in parameters between CA-GREET2.0 and CA-GREET3.0.

		CA-GREET2.0	**CA-GREET3.0**
Crude Refining to CARBOB			
Source (fuel production)		CA Crude	
Efficiency		89%	88.64%
Share of other energy inputs (excluding crude)	Residual oil	24.9%	36.6%
	Diesel fuel	0.0%	0.0%
	Gasoline	0.0%	0.0%
	Natural gas	37.40%	22.6%
	LPG	8.01%	0.0%
	Electricity	3.5%	1.31%
	Hydrogen	26.2%	0.7%
	Butane	0.0%	20.4%
	Blendstock	0.0%	18.4%
Feed loss		0.0%	0.0%
CI, gCO_2e/MJ		13.45	14.81
Crude Refining to ULSD			
Source (fuel production)		CA Crude	
Efficiency		88%	85.87%
Share of other energy inputs	Residual oil	24.9%	20.8%
	Diesel fuel	0.0%	0.00%
	Gasoline	0.0%	0.00%

(excluding crude)	Natural gas	37.40%	71.7%
	LPG	8.01%	0.0%
	Electricity	3.5%	3.7%
	Hydrogen	26.2%	3.6%
	Butane	0.0%	0.2%
Feed loss		0.0%	0.0%
CI, gCO_2e/MJ		14.83	13.58

J-3.3. Comment: The use of loss factor needs to be corrected. Currently, it is applied in the cells C12, C14 and C16 to all the steps in the CI calculation. However, it should only be applied to the steps till the fuel production step including fuel production. It should not be applied to the ethanol T&D, denaturant and iLUC. (LCA1_8-8)

> **Agency Response**: Staff has revised calculations so that denaturant, iLUC, and transportation factors will not include a loss factor.

J-3.4. Comment: More importantly, the CA_GREET model defines the basis for GHG calculations under the LCFS. Scholars, students, analysts, and of course affected parties look to the model to define the methods for GHG analysis. So, simple math errors should be corrected to avoid misunderstandings. (LCA1_8-17)

> **Agency Response:** Staff understands the importance of accuracy in GHG emissions calculations. All models and Calculators released are checked to ensure error-free versions are available for stakeholder use.

J-4. *Starch and Fiber Ethanol Carbon Intensity Calculation*

J-4.1. Multiple Comments: *Default CA-GREET Values for Grain Sorghum Pathways*

Comment: B. Revise default CA-GREET agriculture-related emissions values for grain sorghum pathways

RFA continues to encourage CARB to work with Argonne experts to revisit greet model assumptions regarding grain sorghum production. We believe more current and robust data is available to update key default assumptions regarding grain sorghum fertilization practices, yields, and other key variables. Disparate treatment of corn and sorghum ethanol pathways creates inefficiencies and disturbances in the marketplace, where the two feedstocks are generally treated interchangeably. (RFA1_80-1a)

Comment: Second is how sorghum is dealt with. There are so many details in this regulation. But sorghum is very important for the industry across the United States. And so we produce ethanol from sorghum and we've worked hard with the staff to try and improve the numbers in the GREET model in particular. So we've partnered with Argonne, spent a lot of time.

And so we really appreciate again the work that the staff has done. Our ask is just to try and maintain the numbers that we see in the model right now. (CONESTOGA1_T39-3)

Comment: It appears the new CA-GREET 3.0 and the CI Calculator continue to use out dated assumptions regarding grain sorghum production from the latest version of GREET from Argonne National Laboratory. We encourage CARB to reconsider the agricultural assumptions regarding grain sorghum production and we believe more current and robust data is available to support updating key default values. (RFA1_80-8)

> **Agency Response:** Based on data received from the National Sorghum Producers Association, Argonne National Laboratory updated relevant inputs for grain sorghum. CARB has modified CA-GREET 3.0 to reflect Argonne updates for grain sorghum. For the ethanol production process, co-product, fuel yield, corn oil (interchangeable with sorghum oil) are considered to be interchangeable between these two feedstocks. With these updates, CARB has addressed any perceived inefficiencies in the modeling of ethanol produced from these feedstocks.

J-4.2. *Consider Corn Kernel Fiber Technologies for Tier 1 Classification*

Comment: We support CARB's proposal to include corn fiber ethanol using the Edeniq process under the Tier 1 classification and evaluate its CI using the Simplified Calculator. Several ACE members are working with Edeniq and other technology providers to produce low carbon corn kernel fiber ethanol. We encourage CARB to consider similar corn kernel fiber technologies for Tier 1 classification as well. (ACE1_41-8)

> **Agency Response:** The Simplified CI Calculator embraces technologies for corn-fiber to cellulosic ethanol which use cellulose-type enzymes. If pathway applicants can demonstrate that new technologies can be adequately modeled using the Tier 1 framework, staff will review each new technology to determine the applicability of the Tier 1 Calculator to calculate the CI for each such pathway. If the Tier 1 sheet is incapable to modeling such impacts, applicants can choose to use the Tier 2 framework for their fuel pathway.

J-4.3. *Corrections to Elements of the Carbon Intensity Calculations*

Comment: However, we believe that important work remains to ensure that the LCFS provides optimal market signals to the lowest CI fuels. To that end, we call CARB's attention to Part II of the Growth Energy comment letter, which we adopt in full by reference. Part II identifies important corrections to elements of CI calculations that, if incorporated, will better align the LCFS with its goal of providing proper incentives to low carbon fuels based on sound science. (POET2_B3-3)

> **Agency Response:** Responses to comments from Part II of the Growth Energy comment letter can be found in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard

and Alternative Diesel Fuel Regulations document. The following comments apply: GROWTHENERGY1_B4-23a, 23b, 23c, 23d, 23e, 23f, 23g, 24, 25k, 26. Responses to Appendices D, E and F of the Growth Energy Comment letter are included in this document, including Responses J-1.5, J-2.2, J-2.13, J-2.16, J-2.18a, J-2.18b, J-2.18c, J-2.18d, J-2.18e, J-4.8, J-4.9, J-4.11, J-5.1, J-5.2, J-5.3, J-5.4, J-5.5, J-5.6a, J-5.6b, J-5.6c, J-5.6d, J-5.6e, J-5.6g, J-5.6i, J-5.6j, and J-14.2 in this chapter.

J-4.4. *Corn Ethanol Carbon Intensity is too High*

Comment: Growth Energy's comments to the California Air Resources Board ("CARB" or, the "Board") on the proposed modifications to the LCFS and ADF regulations (collectively, the "Proposed Amendments") are contained in this summary document, which includes several appendices and exhibits that provide an extended analysis of certain issues.

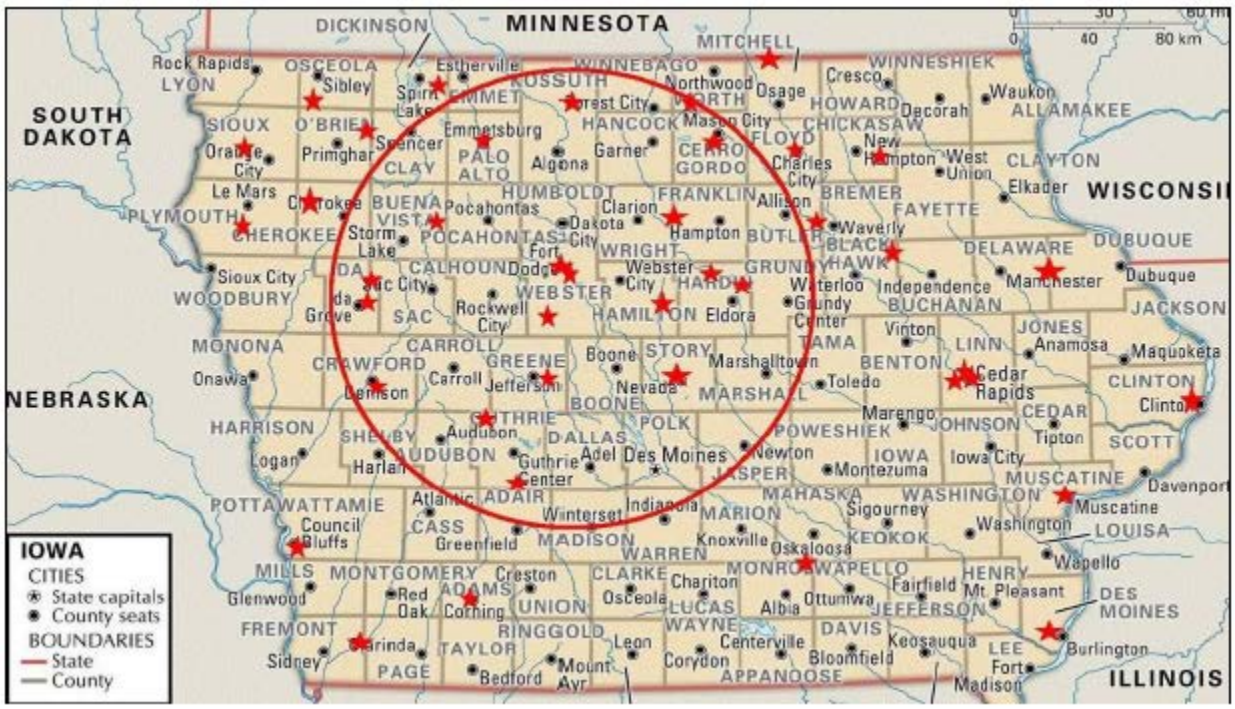
As an initial matter, Growth Energy would like to thank CARB staff for recommending several amendments to the LCFS regulation that update the scientific basis of the program, particularly with respect to the calculation of the carbon intensity ("CI") for corn starch ethanol. Since CARB first considered the LCFS regulation for adoption, Growth Energy has expressed concern that the CI for com ethanol is too high – particularly with the incorporation of land use change ("LUC") impacts – and that the CI for Brazilian sugarcane ethanol is too low. While more work is needed, Growth Energy recognizes the Proposed Amendments show progress on CARB's part in aligning the treatment of com starch ethanol and sugarcane ethanol with "the best available economic and scientific information. . . ." (Health & Saf. Code, § 38562, subd. (e).) (GROWTHENERGY1_B4-4)

> **Agency Response:** Staff appreciates support for updating the scientific basis of life cycle analysis utilizing the best available economic and scientific information. Response to LUC impacts is included in Response J-14 in this chapter. Please see Responses J-5.1, J-5.2, J-5.3, J-5.4, J-5.5, J-5.6a, J-5.6b, J-5.6c, J-5.6d, J-5.6e, J-5.6g, J-5.6i, and J-5.6j in this chapter further explaining Growth Energy's concerns regarding cane ethanol CI values.

J-4.5. Multiple Comments: *Corn Transportation Distance*

Comment: Of particular concern to ACE members is the overly conservative and unrealistic default value for corn transportation distance from farms or corn storage facilities to ethanol plants. The CA-GREET 2013 default <u>average</u> one-way transportation distance is 40 miles. This implies that ethanol plants draw corn uniformly from a circular area with an 80 mile radius. A circle with an 80 mile radius contains 20,106 square miles. The State of Iowa has 56,273 square miles of surface area, less than three 80-mile radius circles. There are more than 40 ethanol production facilities in Iowa. If all of these 40 ethanol production facilities drew uniformly from an 80-mile radius circle, they would draw corn from 804,250 square miles, an area more than 14 times the size of Iowa! We believe this 40 mile average one-way distance is

overestimated by <u>at least</u> a factor of three in Iowa and two in many other states. Below is a graphical illustration of Iowa ethanol production facilities (noted by red stars) and an 80-mile radius circle:



In addition to these facts, the United States Department of Agriculture Office of Energy Policy and New Uses analyzed the concentration of ethanol production facilities and the density of corn supplies and estimated the average one-way corn transportation distance from farms or corn storage facilities to ethanol plants for the 9 major corn and ethanol producing states ranged from 14 miles in Iowa to 23 miles in Ohio (page 5 in report).[1] We urge you to evaluate and properly adjust this corn transportation distance default in CA-GREET 2013.

[1] "2015 Energy Balance for the Corn-Ethanol Industry" https://www.usda.gov/oce/reports/energy/2015EnergyBalanceCornEthanol.pdf

(ACE1_41-7)

Comment: d. CARB's default values for corn transportation distance by truck from the farm to the ethanol plant are inappropriate and unrealistic. The proposed default value of 80 miles is not supported by other analyses and empirical data. For example, a recent analysis by the U.S. Department of Agriculture found that "corn moves by truck relatively short distances to nearby ethanol plants," and that "the average distance to market ranges from about 14 miles for Iowa to 23 miles for Ohio."[2] Thus, even with back-haul miles included, the USDA mileage estimates are less than half, on average, of what CARB is proposing to use for a one-way value. We recommend that CARB

adopt a conservative default farm-to-plant corn transportation distance of no more than 40 miles.

[2] USDA. February 2016. "The 2015 Energy Balance for the Corn-Ethanol Industry." https://www.usda.gov/oce/reports/energy/2015EnergyBalanceCornEthanol.pdf

(RFA1_80-9)

Agency Response: Staff has reviewed both data for certified corn ethanol pathways and the reference provided by the commenter. Based on the review, staff has updated the conditional default transport distance in the starch Simplified CI Calculator to 40 miles by HDD truck.

J-4.6. *Soil Carbon*

J-4.6a. Multiple Comments: *Soil Carbon Effects Associated with Corn Production*

Comment: It is our understanding general commentary regarding the lifecycle analysis modeling used by CARB to determine the GHG emission impacts of various fuels is outside the scope of this rulemaking. Nevertheless, we are compelled to make brief comments about this topic and ask CARB to engage ACE on how to make improvements in this area because it is a priority issue for our members.

Since biofuel lifecycle GHG modeling was first developed by scientists at the U.S. Department of Energy's Argonne National Laboratory more than 30 years ago, corn and ethanol production have experienced significant improvements and efficiencies. As you know, Argonne's GREET model is used to calculate energy use and GHG emissions that occur during the full lifecycle production and combustion of all current and potential transportation fuels. The assumptions used by Argonne scientists in the GREET model are under constant review and updates to the model occur frequently. Current data from the GREET model indicate that corn ethanol's CI is almost 50 percent better than gasoline.

During the past 12 months, ACE members have been analyzing existing data considered in lifecycle GHG modeling in hopes of building consensus for recognizing the significant climate benefits from further expansion of sustainable corn ethanol production and use in the U.S. We have developed a White Paper and are currently in the process of engaging diverse stakeholders on a variety of topics such as modeling the direct effect each biofuel feedstock has on soil carbon stocks, assumptions used to calculate nitrous oxide emissions and lime application of soils, the crediting of ethanol production coproducts, and land use changes.

We support GREET as the gold standard but our examination of existing research has exposed a shortcoming because the model currently fails to account for the direct effect of biofuel feedstock crops on soil organic matter/soil organic carbon stocks.

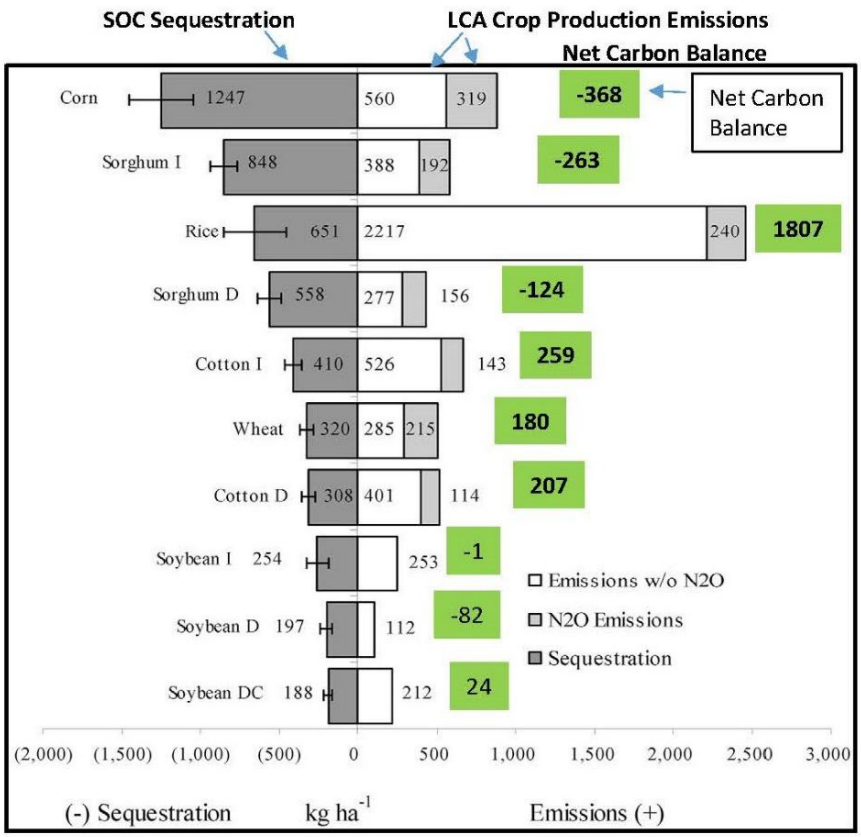
For example, in 2011 Popp et al. estimated the "net" carbon emissions of commonly grown crops in Arkansas.[2] These soil and crop scientists defined "net" carbon emissions as the all-inclusive lifecycle GHG emissions during crop production plus the

effect each crop has on soil carbon stocks. Their peer-reviewed data show that C4 crops such as corn and sorghum sequester more than enough atmospheric carbon in soil to offset their LCA GHG emissions and are "net" carbon sinks. Below is a graphical illustration from Popp et al. of the "net" carbon emissions from several crops:

[2] "Estimating Net Carbon Emissions and Agricultural Response to Potential Carbon Offset Policies". http://agris.fao.org/agris-search/search.do?recordID=US201500052566

Figure 1, page 1134

Carbon equivalent emissions and sequestration by crop including variation in C sequestration due to yield, soil, and tillage effects; I = irrigated, D = unirrigated or dryland, DC = double cropped. Error bars on the sequestration side include variation due to yield, soil type, and tillage effects but exclude expected variation in harvest index and root/shoot ratio. Also note that soybean production entailed no N fertilizer application and hence no N_2O emissions. Additional uncertainty, especially pertaining to N_2O emissions, exists and is not shown here. **Net Carbon footprint in**



As shown above there is a significant difference in the total GHG emissions for major crops. Corn is the most GHG-intense crop (other than rice) due to the fertilizer nutrient requirements to produce corn grain and the large mass of root and above-ground residue. The peer-reviewed Popp et al. research indicates this large mass of root and above-ground corn residue builds soil organic carbon enabling corn (and sorghum) production to result as net GHG sinks. Crops with C4 atmospheric carbon fixation pathways such as corn and sorghum produce far more calories and protein per unit of

land, water and fertilizer nutrients than C3 crops so it is not a surprise corn and sorghum stand out in terms of "net" LCA carbon emissions.

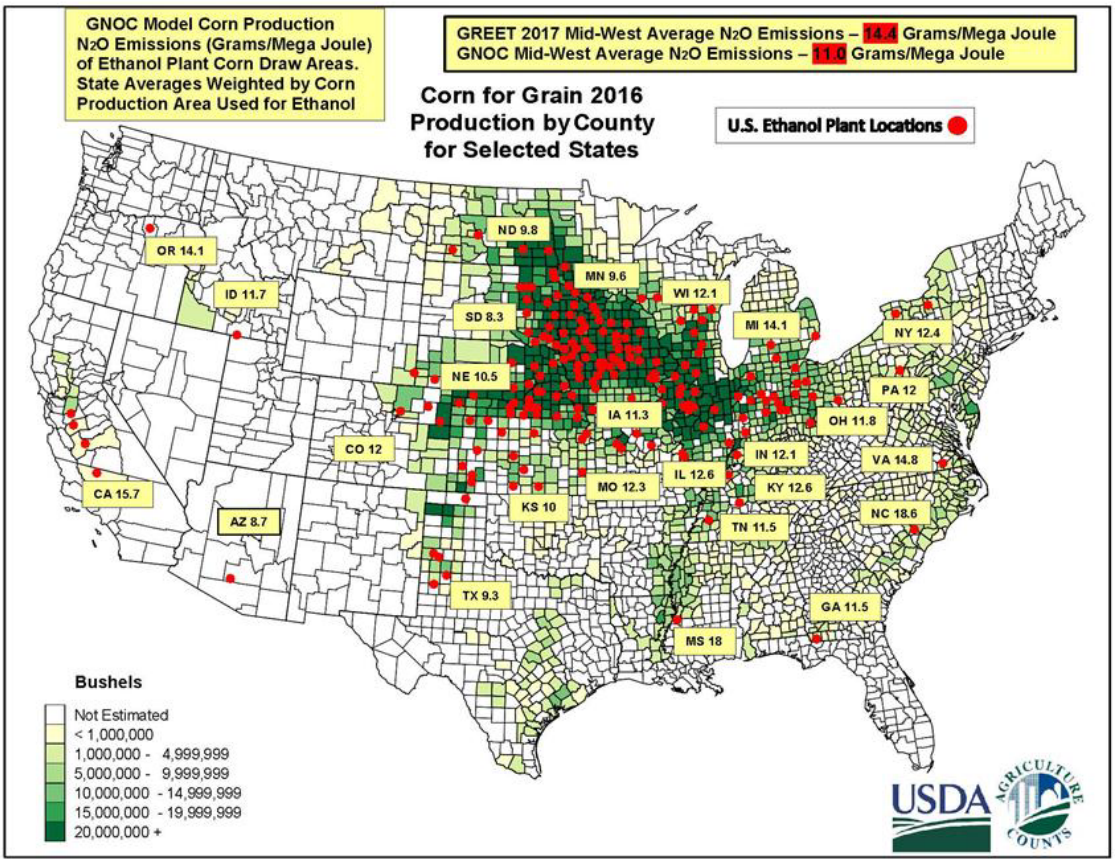
In addition to the Popp et al. study, Kansas State University researchers collaborated to publish a peer-reviewed paper in 2006 titled *"Economic Feasibility of No-Tillage and Manure for Soil Carbon Sequestration in Corn in Northeastern Kansas*."[3] This paper also calculated the "net" carbon emissions of corn production and conclusively verified soil carbon sequestration over 9 years with beginning and ending soil carbon analysis. In all cases, including conventional till versus no-tillage and manure nitrogen versus synthetic nitrogen under two different rates, continuous corn production was a large "net" GHG sink. This research proves a link between crop production and soil organic carbon which has large impacts on the lifecycle carbon intensity of biofuels. If CARB expects the LCFS to achieve its desired result the lifecycle modeling must reflect the latest-available science, including data on soil carbon, and recognize ethanol and corn production is constantly improving.

[3] https://dl.sciencesocieties.org/publications/jeq/abstracts/35/4/1364

Many environmental, soil and crop scientists also consider the soil nitrous oxide (N_2O) modeling and accounting in the GREET model as archaic. N_2O emission factors used in current GREET models are based on 1980s conditions. We urge you to consider the use of a modern, sophisticated yet simple-to-use, site-specific nitrous oxide emissions model such as the Global Nitrous Oxide Emissions Calculator (GNOC) to determine N_2O emissions during biofuel feedstock production.[4]

[4] http://gnoc.jrc.ec.europa.eu/

The GNOC was designed to estimate site-specific nitrous oxide emissions for worldwide crop production and is frequently updated to represent the best and latest science. The model interacts with an extensive database of site-specific soil and environmental climate conditions and follows Intergovernmental Panel on Climate Change (IPCC) guidance on key N_2O emission factors. Using the GNOC model with guidance from University scientists, ACE estimated the average N_2O emissions from U.S. corn land used produce corn ethanol and compared that with GREET 2017 Midwest average N_2O emissions. Below is a graphical illustration of this comparison.



U.S. Department of Agriculture, National Agricultural Statistics Service

As indicated above, this significantly more sophisticated and robust GNOC model estimation of Midwest corn for ethanol production N_2O emissions indicates a 3.4 gram per mega joule reduction (11 grams/MJ under GNOC versus 14.4 grams/MJ with GREET 2017) in corn ethanol LCA carbon intensity. We urge you to consider this new science.

ACE's White Paper sifts through the above-mentioned lifecycle science and current state-of-play regarding the production of corn ethanol and highlights where updates in lifecycle modeling assumptions should be made to ensure entities such as CARB are relying on the latest science to maximize and incentivize every opportunity to sequester CO_2 as quickly as possible. Once we have achieved consensus with various NGOs and stakeholders on the latest lifecycle data and need for updates in modeling, our intention is to approach CARB and discuss the need to support this new research in your future policy decisions. (ACE1_41-9)

Comment: b. RFA encourages CARB to work with experts from Argonne, USDA, academia, and other entities to ensure that both the Argonne GREET and CA GREET modeling frameworks appropriately characterize all soil carbon effects associated with corn production, including the opportunity for net carbon sequestration in certain corn production systems. (RFA1_80-13)

Agency Response: Due to uncertainty in attribution of sequestration of carbon from agriculture, staff has not considered this aspect in the life cycle analysis of fuels in this round of rulemaking. If advances in science and data inform staff of certainty of sequestration and methodologies to quantify such benefits, potential consideration of such impacts may be considered in a future rulemaking.

Life cycle analysis used in the LCFS recognizes improvements in individual ethanol production facilities, and reflects regional average corn production practices. Corn farming inputs in the GREET model represent average farming practices in corn growing regions in the U.S. and include regions where no-till is practiced. Certain GHG benefits of no-till agriculture, such as reduced fuel demand, are therefore, reflected in the life cycle analysis. As for the consideration of sequestration, in addition to complexities of soil organic modeling, quantification of soil carbon sequestration (or loss) depends on many factors including agriculture practices, soil characteristics, climate and topography. The commenters cite research (ACE white paper[39]) supporting net carbon sequestration from agricultural operations particularly from C4 crops.

Given the lack of scientific consensus on carbon sequestration in soil among academic and other experts and the non-consideration of such impacts in the Argonne 1_2016 model, staff has not included impact on soil carbon sequestration in the current life cycle analysis of transportation fuels. Staff will continue to engage with experts from academia, industry, non-governmental organizations (NGOs) and other stakeholders to develop a better understanding of soil carbon effects. In addition, ensuring permanence of sequestered soil carbon can complicate the inclusion of soil carbon sequestration in life cycle analysis. As stated by the commenter, once there is consensus among researchers and other experts in addition to NGOs, staff will evaluate inclusion of carbon sequestration impacts from agricultural activities in future rulemaking.

For response to potential reductions in enteric fermentation from use of DGS as an animal feed ration detailed in the ACE white paper[40] see response to GROWTHENERGY1_B4-23a of the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

N_2O emission factors in CA-GREET3.0 are based on Tier 1 IPCC guidelines.[41] If country-specific factors become available for all crop-producing regions of the world, the consideration of Tier 2 IPCC factors will be evaluated in future

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[39] Ron Alverson. *Re-thinking the Carbon Reduction Value of Corn Ethanol*. White paper, November 2015. http://www.ethanolacrossamerica.net/pdfs/CFDC-Alverson-WP.pdf

[40] Ibid.

[41] *N2O Emissions from Managed Soils, and CO2 Emissions from Lime and Urea Application*, Chapter 11, 2006 IPCC Guidelines for National Greenhouse Gas Inventories vol 4 (Hayama: IGES) IPCC, De Klein, C. et al., (2006). Available: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/4_Volume4/V4_11_Ch11_N2O&CO2.pdf

rulemaking. With regard to evaluating site-specific N_2O emission factors using models such as the GNOC model and lower N_2O emissions due to impact of precipitation, staff will continue to consult with stakeholders and experts and will evaluate incorporating updated N_2O emission factors in future CA-GREET updates.

J-4.6b. Comment: …overly conservative defaults need to be addressed. **Specifically, RPMG requests the following revisions: … establish Simplified CI Calculator default values that are reflective of real world industry practice.**

RPMG requests the default distance for Midwest corn transport be revised to 40 miles and the temporary fuel pathway code CI for corn starch ethanol remain at 75.97 g/MJ. The proposed simplified calculator and regulations create a disadvantage to ethanol producers with overly conservative and inaccurate defaults. The proposed defaults make the carbon intensity of the fuel unrealistically high and as a result, act as a barrier to optimal program contributions.

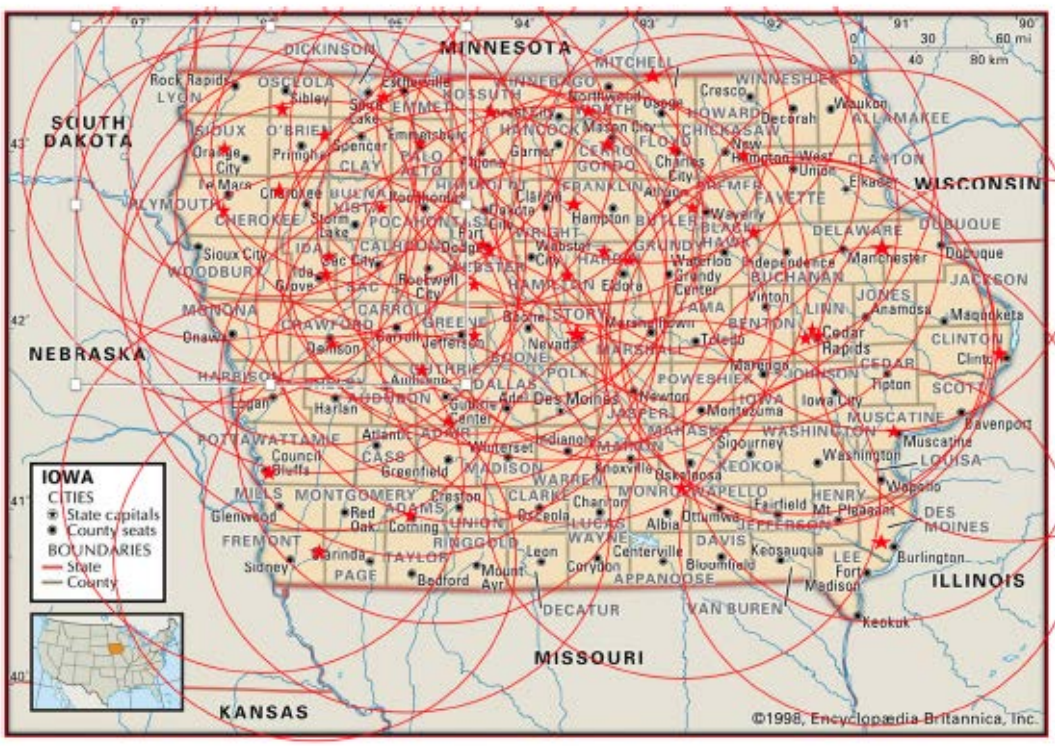
RPMG requests a default of 40 miles for Midwest corn transport distance in Tier 1 corn ethanol pathways. The proposed simplified calculator has a Midwest corn transport distance of 80 miles. RPMG has previously submitted multiple comments drawing attention to this punitive default and its implications. RPMG appreciates CARB staff's willingness to include site specific optionality, but the calculator must prioritize and include a reasonable default.

The U.S. Department of Agriculture calculated average distances that corn is shipped to ethanol plants in nine Midwestern states and found the average corn transport distance for ethanol plants in the Midwest is 19.1 miles—four times lower than the default.[1] A map was created for Iowa to illustrate this issue. The map shows all of the ethanol plants marked with 80-mile radius drawn around each.[2] The illustration (attached for reference) clearly shows, if a plant had a corn transport distance anywhere near 80 miles, the corn producer would have to drive past several other ethanol facilities. For a corn producer to be incentivized do this, the ethanol facility would need to outbid all of the closer facilities. This would significantly increase a plant's cost of production and is economically unsustainable. This simple economic concept is true throughout the Midwest.

[1] 2015 Energy Balance for the Corn Ethanol Industry; Energy Balance Study Appendix B1

[2] See Attachment A- Map created by Ron Alverson, of the American Coalition for Ethanol.

Attachment A



(RPMG1_64-9)

Agency Response: Please reference Response J-10.5 in this chapter regarding the temporary CI value for starch ethanol.

The starch Simplified CI Calculator uses industry average values for standard inputs calculated using applicant data from hundreds of pathways certified between 2011 and 2017. Based on CI calculations for starch ethanol pathways using the Simplified CI Calculator, pathways CIs for starch ethanol are lower compared to the corresponding values using CA-GREET2.0. The commenter's reference to overly conservative and inaccurate defaults leading to higher CIs are, therefore, without merit. Regarding the feedstock transport distance of 80 miles, this conditional default value has been changed to 40 miles in the Calculator. Please refer to Response J-4.5 in this chapter.

J-4.7. Multiple Comments: *Simplified Calculator*

Comment: We are also concerned the proposed Simplified Calculator does not recognize or reward individual biofuel producer innovations. Under the proposal, Tier 1 Simplified CI Calculator pathways do not account for biogas use, site specific chemical use, or no-till farming. These areas of ethanol industry innovation have demonstrated substantial carbon emission reductions in approved pathways, academic research and documented recommendations submitted to CARB. Further, according to our members, if a producer wishes to benefit from a CI reduction through biogas process

energy or site-specific chemical use, they must do so under a Tier 2 pathway which involves a more expensive and time-consuming process. The proposed substantiality requirement for new pathway applications further deters the industry from pursuing innovative technologies and efficiencies. To encourage and reward innovation, the Simplified Calculator should be revised to include optional columns to recognize and quantify these efforts. (ACE1_41-6)

Comment:

1. No Biomass as fuel input (previously in the Tier 1 calculator)
2. No Biogas as fuel input (previously in the Tier 1 calculator)
3. No ability to enter user defined chemical inputs. Producers can and will optimize chemical input use. (POET1_129-1)

Comment: RPMG requests the proposed CI simplified calculator be revised to allow for the use of optional columns that account for individual producer innovations. The ethanol industry runs on innovation. Unfortunately, the proposed Simplified Calculator does not recognize or reward individual producer innovations. Under the proposed regulations, Tier 1 Simplified CI Calculator pathways do not account for biogas use, site specific chemical use, or no till farming. These areas of ethanol industry innovation have demonstrated substantial carbon emission improvement in approved pathways, academic research and documented recommendations submitted to CARB over the past ten years of LCFS program history. Further, if a producer wishes to benefit from a CI reduction through biogas process energy or site specific chemical use, they must do so under a Tier 2 pathway which involves a more expensive and time intensive process. The proposed substantiality requirement for new pathway applications further deters the industry from pursuing these types of innovation. To encourage and reward innovation, the simplified calculator should be revised to include optional columns that recognize and quantify these efforts. (RPMG1_64-11)

Comment: e. We understand that the goal of the simplified calculator is to reduce the number of user-defined input variables and simplify the calculations used to derive CI values. However, we believe users should have the ability to enter unique, non-default data for chemical usage. (RFA1_80-10)

> **Agency Response:** In response to comments requesting the option to account for biogas and biomass process energy inputs, staff modified the Simplified CI Calculator for Starch and Fiber Ethanol to account for biogas and biomass use as process fuels.
>
> Staff did not include site-specific inputs for chemical use as requested in these comments. Standard values used in the starch Simplified CI Calculator are derived from starch ethanol applications certified in 2016 and 2017. Offering a site specific option for chemical use is likely to result in a minimal change in pathway CI compared to the standard value. Inclusion of such an option however, brings with it a significant burden for third-party verifiers to include

verification of chemical use at individual ethanol plants, while increasing verification costs. It runs counter to the primary purpose (i.e., expedite review and certification) of developing a Simplified CI Calculator. Staff is, therefore, not including a site-specific option for chemical use in ethanol plants. If a facility can demonstrate a reduction in CI that meets the substantiality threshold through innovation in chemical use, the Tier 2 pathway process allows for recognition of this CI reduction.

Regarding the request to recognize the GHG benefits of soil carbon sequestration through no-till agricultural practices, please refer to Response J-4.6a in this chapter.

J-4.8. *Farming Emissions for Sorghum Ethanol*

Comment: The emission calculations of the sorghum ethanol are 4 g/MJ higher than the corn ethanol and the difference is all in the feedstock emission area. (GROWTHENERGY1_B4-110c)

Agency Response: Farming inputs for grain sorghum production are higher compared to corn (based on Argonne National Laboratory) and consequently, CIs for sorghum ethanol are nominally higher by about 4 g/MJ.

J-4.9. *Hidden Sheets in the Simplified CI Calculator*

Comment: There are 25 hidden sheets in the model. There does not appear to be any information transferred in from the hidden sheets which suggest that these sheets could and should be removed.

Also rows 85 to 87 on the EF Tables sheet are not used and should be deleted. (GROWTHENERGY1_B4-110d)

Agency Response: Staff was unable to locate any hidden sheets in the publicly released starch Simplified CI Calculator. It is likely that the comments refer to previous versions of the Calculator released for public comments prior to the March 6, 2018 release.

J-4.10. *Drying Energy for DGS*

Comment: The ARB has developed verification spreadsheets that enable the recording of energy used for drying. Several ethanol plants have taken advantage of this fuel pathway and we are investigating it for one of our facilities. Over the past several years several applications have been submitted and rejected because they did not provide direct measurements to document energy use associated with drying.[1] The ideal approach would be for ethanol plants to install flow meters on all of their gas combustion equipment and amp meters on all of their electricity uses, which was communicated to ethanol producers that applied for such pathways.

[1] For example, one application solved a system of equations for ethanol plant operation with and without DGS drying to determine the amount of natural gas and electric power associated with DGS drying.

Natural gas used for drying is obviously the primary energy that distinguishes the production of ethanol associated with dry and wet. However, electricity used to operate conveyors and equipment associated with drying is also a significant energy use and has a significant contribution to the carbon intensity of dry DGS ethanol.

We are requesting that the ARB modify its verification spreadsheet to include the opportunity or option to add electricity used for drying based on amp meters and data loggers. This opportunity is made available to other biorefineries also, i.e. soybean crushers that produce both biodiesel and soybean oil internal to one facility might also measure their electricity consumption and natural gas usage to separate the energy requirements for biodiesel production. We are requesting the same treatment as an option for facilities that have installed this equipment. The opportunity to monitor electricity usage provides an incentive for continuous improvement and helps fuel producers understands the contribution of all of their energy and inputs to their carbon intensity and motivates the further reduction of greenhouse gas emissions. Measuring power consumption for drying will not complicate verification and will only motivate fuel producers to further reduce GHG emissions. (KAPPA1_74-2)

> **Agency Response:** The most significant impact on carbon intensity is attributable to natural gas usage for drying DGS. Electrical energy used by conveyors in transporting the dry DGS stream accounts for only a small portion of the total electrical energy used by the plant. Differentiating DGS streams by electrical energy use introduces an additional complexity in the pathway analysis of existing provisions to differentiate ethanol streams based on natural gas used to dry DGS fractions. One of the objectives of the LCFS program is to incentivize existing producers to upgrade existing processes to achieve measurable reductions in emissions. Differentiating DGS streams by the inclusion of an option to disaggregate electricity use is not such a measure and staff will, therefore, not consider this request from the commenter.

J-4.11. *Values from Tier 1 Calculator*

Comment: The GHG emissions for corn ethanol are about 49 g/MJ without ILUC and 68 with ILUC. Individual plants with vary. This is significantly lower than the existing Tier 1 calculator that has values of about 83 g/MJ with ILUC. (GROWTHENERGY1_B4-110b)

> **Agency Response:** The value of 83 g/MJ reported by the commenter with the use of the Tier 1 Calculator is not supported by listing inputs used to calculate this value. Staff is, therefore, not able to replicate this value. Lower emissions burden for corn farming from GREET 1_2016, refinements to truck payload and fuel economy, standardized inputs using industry average values in the Tier 1 Calculator and site specific denaturant use in totality are expected to lower the CI for corn ethanol using CA-GREET3.0 compared to CA-GREET2.0.

J-5. *Sugarcane Ethanol Carbon Intensity Calculation*

J-5.1. Multiple Comments: *Transport and Distribution Emissions Factors*

Comment: The same emissions factor is used for truck transport in Brazil as in California. This should not be the case as there is a different power mix in the two regions. The Brazilian results are shown in the following table.

	CA GREET	Calculator
	Emissions per mmBTU-mile	
VOC	0.0022	0.0022
CO	0.0073	0.0073
CH_4	0.0179	0.0180
N_2O	0.0000	0.0000
CO_2	7.6835	7.6757
GHG	8.1616	8.1532
GHG, g CO_2/gallon	0.623	0.622

The difference is due to the rounding of the GWP for VOC and CO. The larger issue is that these are not the same emission factors used for the corn ethanol calculator even for the California portion of the transport. (GROWTHENERGY1_B4-117)

Comment: 2. The sugarcane transportation emissions are about half of what they should be due to the use of incorrect emission factors. (GROWTHENERGY1_B4-121)

> **Agency Response:** The CA-GREET3.0 model calculates GHG emissions for the indirect use of electricity in transport and distribution (T&D). Transport and distribution emission factors for truck would vary depending on the electricity mix in a given region. Hence, staff proposed to use different emission factors for truck transport in California and Brazil by considering the electricity mix specific to these regions in the Simplified CI Calculator for Sugarcane-derived Ethanol.

J-5.2. Multiple Comments: *N_2O Emissions from Nitrogen in Fertilizer*

Comment: We have several comments on the sugarcane ethanol emissions: …
(3) N_20 emissions from nitrogen in fertilizer are too low and not consistent with N_20 emissions from fertilizer in other countries. (GROWTHENERGY1_B4-107c)

Comment: The N_2O emissions factors in CaGREET3.0 are shown in Table 8. The N_2O fractions are shown for the nitrogen from the biomass and nitrogen from fertilizer. All of the biomass nitrogen is at 1.225%, which is the IPCC default level for biomass. The nitrogen from fertilizer is given an extra 0.1% to account for volatilization of nitrogen from fertilizer, which does not occur for the biomass. But the value being used for fertilizer in Brazil is 1.220%. This value comes from the GREET model. This value for fertilizer in Brazil should be changed to 1.325% to be consistent with the IPCC default value, and to be consistent with N_2O from fertilizer in the US.

Table 9. N_2O Emissions: N in N_2O as % of N in N Fertilizer and Biomass							
Biomass						Fertilizer	
Corn Farming	Switchgrass	Miscanthus	Corn Stover	Sorghum	Sugarcane	Nitrogen fertilizer in the US	Nitrogen fertilizer in Brazil
1.225%	1.225%	1.225%	1.225%	1.225%	1.225%	1.325%	1.220%

When the N in N2O in fertilizer is increased to 1.325% from 1.220%, the CI increases by 0.43 gCO2e/MJ (56.32 instead of the 55.89 in Table 8) (GROWTHENERGY1_B4-107f)

> **Agency Response:** The N-to-N_2O conversion rate and emissions factor was adopted from 2006 IPCC Guidelines.[42] To ensure consistency across all crops, the conversion factor for N in Fertilizer used in Brazil has been updated to 1.325 percent.

J-5.3. Multiple Comments: *Fertilizer Emissions for Sugarcane*

Comment: We have several comments on the sugarcane ethanol emissions: … (2) the amount of fertilizer applied to sugarcane is 40% lower than the Brazilians use in their emissions model, … (GROWTHENERGY1_B4-107b)

Comment: The VSB also reports the other inputs that are summarized and compared to the CaGREET3.0 values in the following table.

Table 6. VSB Inputs vs. CaGREET3.0 (Sugarcane)		
	CaGREET3.0	VSB
Nitrogen, g/tonne cane	800	1,342
Phosphorus, g/tonne cane	300	203
Potassium, g/tonne cane	1,000	1,420

Not only is the biomass N underestimated in GREET but the synthetic fertilizer is also underestimated. The following table compares the nitrogen inputs from GREET 2013, CA GREET 2.0, and the best available data.

[42] IPCC (2006). N2O emissions from managed soils, and CO2 emissions from lime and urea application. 2006 IPCC Guidelines for National Greenhouse Gas Inventories vol 4 (Hayama: IGES) Chapter 11. Available at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/4_Volume4/V4_11_Ch11_N2O&CO2.pdf

Table 7. Nitrogen Input Comparison for Sugarcane (Kg N/tonne cane)			
	CaGREET 2.0	CaGREET3.0	Best Available Data
Fertilizer	800	1,025	1,342
Crop Residue	1,036	705	864
Filtercake	36	36	36
Vinasse	205	205	205
Roots	0	0	305
Total	2,077	2,302	2,752

The carbon intensity of sugarcane ethanol is shown with CaGREET3.0 and the best available data in Table 8. Emissions using best available nitrogen data are 4.78 g/MJ higher than CaGREET3.0. Clearly, at least the 305 g root nitrogen should be added to CaGREET3.0 since it is currently not counted.

Table 8. CI of Sugarcane Ethanol		
Scenario	g CO2e/MJ	
	Feedstock Production CI	Total CI
CaGREET3.0	21.17	51.11
Best Available Data	26.13	55.89

(GROWTHENERGY1_B4-107e)

Agency Response: The inputs for chemical/fertilizer use for Brazilian sugarcane in the CA-GREET3.0 model were adopted from the Argonne National Laboratory (ANL) GREET1_2016 model. The chemical and fertilizer use in this version of the Argonne model are detailed in a study by Wang et al., 2012 (Table 2 in this article).[43] Another research study by Seabra et al. (2011)[44] included values (Table 1 in this article) which support the fertilizer use in the GREET1_2016 model. Please see Response J-5.5 in this chapter for response to comments regarding biomass nitrogen.

J-5.4. *Emission Factor for Ethanol Production*

Comment: The ethanol production emission factor in the simplified calculator is much lower than it is in CA GREET. In the simplified calculator it is the sum of emissions from residual oil, lime use, and the non-biogenic emissions of bagasse combustion.

CA GREET included emissions from burning straw as well as burning bagasse. When the straw burning emissions are removed from CA GREET we get the values in the following table. It is not clear where the errors in fuel oil and lime are in the calculator

[43] Wang et al, 2012. "Well-to-wheels energy use and greenhouse gas emissions of ethanol from corn, sugarcane and cellulosic biomass for US use," Environ. Res Lett, 7, 045905 (Table 2). http://iopscience.iop.org/article/10.1088/1748-9326/7/4/045905/pdf.

[44] Seabra, J.E.A. et al, 2011. "Life cycle assessment of Brazilian sugarcane products: GHG emissions and energy use," Biofuels, Bioprod. Bioref., Volume 5, 2011.

as they are fixed values. The fuel oil emissions are from an assumption that 10% of the lubricants are combusted. It is much more likely that 100% of the spent lubricants are either burned or used for dust suppression where they are eventually oxidized.

	CA GREET	Calculator
	Emissions per gallon of ethanol	
Fuel oil	2.99	9.9
Lime	37.35	48.8
Bagasse combustion	175.16	168.3
Total	222.5	227.0

The simplified calculator asks for the amount of externally acquired bagasse in column 1 of the Calculator tab but this value does not go anywhere. However the power that is produced from imported bagasse is excluded from the electricity credit calculation. (GROWTHENERGY1_B4-116)

Agency Response: There are no errors in the cane ethanol production emission factor. The Argonne GREET1_2016 model assumes that 10 percent of the fuel oil used as a lubricant is lost during operation. This is the same approach used in CA-GREET3.0. Residual oil as a proxy for emissions from fuel oil oxidation. Currently, there are no data or published reports that provide information on the final disposition of used fuel oil. If such data become available, appropriate changes will be considered in the life cycle analysis of this pathway.

The value of lime usage during ethanol production in the CA-GREET3.0 model is identical to the value adopted in the Simplified CI Calculator for Sugarcane-derived Ethanol. This value, converted in CA-GREET3.0 from grams per metric tonne sugarcane to grams per gallon of ethanol production, was adopted from a survey of 93 mills (Seabra et al, 2011).[45] In addition to bagasse combustion, straw burning emissions (corresponding to the mechanized harvest rate) are also included in the Feedstock Production Phase of the sugarcane-derived ethanol life cycle analysis in the Simplified Calculator and the model.

To prevent facilities from potentially 'gearing' to lower the CI of their fuel pathway by using externally sourced biomass, the Simplified CI Calculator subtracts an amount of electricity corresponding to imported bagasse from the total electricity exported (substantiated by utility receipts). This limits co-product credit only to the portion of electricity generated from the bagasse (to correspond to the juice used in ethanol production) in the production facility.

[45] Seabra, J.E.A. et al, 2011. "Life cycle assessment of Brazilian sugarcane products: GHG emissions and energy use," Biofuels, Bioprod. Bioref., Volume 5, Pages 519-532, 2011 (See Table 2).

J-5.5. Multiple Comments: *Nitrogen Content in Sugarcane Biomass*

Comment: We have several comments on the sugarcane ethanol emissions: (1) the quantity of nitrogen in sugarcane in aboveground residues has been set to the lowest value found in literature; also the nitrogen in the root biomass is not included in GHG calculations, … (GROWTHENERGY1_B4-107a)

Comment: The CaGREET3.0 value for the nitrogen content of the aboveground biomass emanates from GREET 2012 rev 2. The data sources and the values are shown in the following table.

Table 5. GREET Sugarcane Biomass N Content

Source	Value
Macedo [5]	0.37%
Seabra et al. [6]	0.60%
Lisboa[7]	0.50%
Gava et al. [8]	0.64%
Adopted in GREET 2012	0.37%

[5] *Sugar Cane's Energy: Twelve studies on Brazilian sugar cane agribusiness and its sustainability*, Macedo, I.C., 20072nd ed. UNICA
[6] *Life cycle assessment of Brazilian sugarcane products: CHG emissions and energy use*, Seabra, J., Macedo, I., Chum, H., Faroni, C., Sarto, C. A Biofuels, Bioproducts and Biorefining, 2011, VS, 519-532
[7] *Bioethanol production from sugarcane and emissions of greenhouse gases- known and unknowns.* Lisboa, C.C., Butterbach-Bahl, K., Mauder, M., Kiese, R., 2011GCB Bioenergy 3, 277-292.
[8] Urea and sugarcane straw nitrogen balance in a soil-sugarcane crop system, Gava, G.J. de C., Trivelin, P.C.O., Vitti, A.C., Oliveira, M.W. de, 2005. Pesquisa Agropecuaria Brasileira 40, 689-695.

GREET adopted the lowest value in the literature for sugarcane. There is no explanation for the selection of this value in the ISOR or related materials. Nor is there any evidence to suggest this value is realistic. In fact, the studies adopted after 2012 show the value should be much higher. The Leite paper, for example, recently measured the nitrogen content.[9] They reported a value of 0.54% for nitrogen. Looking at the reported N content of biomass per tonne of sugar cane, they found a value of 864 g N/tonne of cane. This does not include the nitrogen in the roots.

9 *Nutrient Partitioning and Stoichiometry in Unburnt Sugarcane Ratoon at Varying Yield Levels*, Leite, J.M., Ciampitti, I.A., Mariano, E., Vieira-Megda, M.X., Trivelin, P.C.O., Frontiers in Plant Science, 20 April 2016.

The nitrogen inputs values in CaGREET3.0 are also understated because they do not include nitrogen in the roots. The importance of including nitrogen in the roots was demonstrated in a discussion of the Canasoft model that is part of the Virtual Sugarcane Biorefinery (VSB) modeling system (Bonomi et al, 2016). That study found that the sugarcane root system is renewed each year by re-growth of ratoon. Emissions of root system are estimated using the root's nitrogen content and the amount of root system, calculated with a root-stalks ratio of 0.2. The root nitrogen content considered is 0.514%. This reveals there is an additional 304 g N/tonne of cane from the roots. The total biomass N is therefore 1,168 g N/tonne of cane, 23.5% higher than the value in CaGREET3.0. (GROWTHENERGY1_B4-107d)

Agency Response: Please see response to GROWTHENERGY1_B4-54e in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations document.

J-5.6. *Sugarcane Ethanol Calculator*

J-5.6a. Multiple Comments: *Conversion Factor for VOC and CO Emissions*

Comment: The sugarcane ethanol calculator needs to be cleaned up. There are a lot of calculations on sheets EF Tables and EF General that take emissions in g/MJ from CA GREET and then convert the emissions to g/tonne, when the g/tonne emission factor can be taken directly from CA GREET. For many of the calculations the conversion of VOC and CO emissions to CO_2eq is done with rounded emission factors rather than the actual values used in CA GREET. This leads to small differences in the emission factors and the potential for errors since the GWP conversion factors are hard coded in the calculator. We found at least one error in coding where the wrong conversion factor was used. (GROWTHENERGY1_B4-111a)

Comment: As noted above, in the calculator the conversion of CO and VOC to GHG emissions is generally hard code and the factors used have been rounded to two decimal points. The calculator underestimates the CO emissions and overestimates the VOC emissions as shown below.

	CA GREET	Calculator
	GWP Conversion	
VOC	3.1167	3.12
CO	1.5714	1.57

(GROWTHENERGY1_B4-111d)

Comment: The comparison of the ocean transport emission factors is presented below. The differences are again due to the GWP rounding in the calculator.

	CA GREET	Calculator
	Emissions per mmBTU-mile	
VOC	0.0010	0.0010
CO	0.0022	0.0022
CH_4	0.0020	0.0020
N_2O	0.0000	0.0000
CO_2	1.0833	1.0831
GHG	1.1408	1.1472
GHG, g CO_2/gallon	0.0871	0.0876

(GROWTHENERGY1_B4-118)

Agency Response: Staff has made appropriate corrections to the Tier 1 Simplified CI Calculator for Sugarcane-derived Ethanol. The layout of the EF Tables and EF General worksheets has been refined.

1. For GWPs, please see Response J-5.6d in this chapter.
2. The conversion factor has been updated (see response to GROWTHENERGY1_B4-55 in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

J-5.6b. **Comment:** There is one sheet, Feasibility Report 1, that is hidden and it should be visible for full transparency. (GROWTHENERGY1_B4-111b)

Agency Response: It appears that the hidden worksheet entitled "Feasibility Report 1" is a self-generated report when the "Calculate" button is pressed (which executes a macro in Excel). The Simplified CI Calculator has been updated to eliminate generation of this report.

J-5.6c. **Comment:** The critical parameters are in rows 131 and 142 on the Calculator sheet. These emissions factors should all be the same as the values in CA GREET 3.0. When CA GREET 3.0 is used it needs to be set up on the Region Selection sheet. Setting the electricity to the Brazilian mix in cells B8 and E8 is obvious but the appropriate setting for the crude oil and natural gas setting is not obvious. The natural gas selection does not have an impact on the emission factor. The crude oil selector has a very small impact of the emission factors. We have set the regions to Brazil for the electricity and the US parameters for natural gas and crude oil. This appears to be what CARB did. (GROWTHENERGY1_B4-111c)

Agency Response: This appears to be a conclusion from the commenter and does not require a response.

J-5.6d. Multiple Comments: *Farming Emissions*

Comment: The emission factors from the calculator and from CA GREET are compared in the following table.

	CA GREET	Calculator
	g CO_2eq/tonne cane	
Farming	8,377	7,819
Fertilizer	8,394	8,393
N_2O	11,279	11,279
Total	28,049	27,491

The farming emissions in the calculator appear to include VOC emissions from bulk terminal that is not used in CA GREET and have applied a GWP factor of 1.57 instead of 25 to the methane emissions (AP 39 in the EF Tables Sheet). It is not clear what the bulk terminal emissions would be for sugarcane farming but the impact is only 24 g/tonne but the methane GWP has an impact of about 580 g/tonne (2%) and accounts for most of the understatement of emissions. (GROWTHENERGY1_B4-112)

Comment: 1. The farming emission factor is too low due to the use of 1.57 instead of 25 for the methane GWP (GROWTHENERGY1_B4-120)

> **Agency Response:** Staff has fixed this error in the Simplified CI Calculator for Sugarcane-derived Ethanol and, therefore, addressed any potential underestimation of emissions from these pathways.

J-5.6e. Comment: The emission factor for the cane and filtercake emissions is a dynamic calculation. It uses emission data on tonne-mile basis from CA GREET and then multiplies it by the miles, adds the filtercake transport emissions calculated in a similar factor and then applies it to the tonnes of cane transported. The emission factor therefore changes when the miles transported changes.

The model uses incorrect emission factors from CA GREET. On the EF Tables sheet the composite emission factor is calculated in rows 9 to 13, columns C to H. The emission factors in column C for the HDD truck are not the same as they are in CA GREET as shown in the following table.

	CA GREET	Calculator
	HDD (grams/ton-mile cane transported)	
VOC	0.083	0.038
CO	0.275	0.131
CH_4	0.673	0.180
N_2O	0.001	0.002
CO_2	289	136.45
GHG	307	141

The calculator again understates the emission factor for sugarcane ethanol, in this case by more than a factor of two. (GROWTHENERGY1_B4-113)

Agency Response: The error has been corrected in the Simplified CI Calculator and the CA-GREET3.0 model to reflect a payload of 17 tons used in the GREET 1_2016 Argonne version of the model.

J-5.6f. Comment: 2. What ethanol yield per ton of sugarcane is used in Ca GREET3.0 (gallons per ton)? I noticed that ethanol yield for corn is a required input, but see no reference to that in Table 26 for cane. That would have a significant effect on each plant's CI. Is it a required input, and if so, why does Table 26 not say so? (TD1_26-2)

Agency Response: Ethanol yield is not a calculated value used in the final CI calculation in both the starch and sugarcane ethanol Simplified CI Calculators. Total production volumes of ethanol reported by the facilities are used to calculate CIs for these pathways. It is quite likely that the commenter is referring to the basic framework in the CA-GREET3.0 model (a modified version of the Argonne 1_2016 version) which requires yields to calculate pathway CIs in contrast to the Simplified CI Calculators which require actual production inputs to calculate CIs (also subject to verification). Table 26 is part of the documentation of the CA-GREET3.0 model. Specific instructions for use of the sugarcane Simplified CI Calculator are included in the Tier 1 Simplified CI Calculator Instruction Manual.

J-5.6g. Comment: The straw burning emissions are close and the difference is caused by the GWP conversion factors for VOC and CO.

	CA GREET	Calculator
	Emissions per tonne of cane	
VOC	1,499.4	1,499.4
CO	19,706.4	19,706.4
CH_4	578.3	578.3
N_2O	15.0	15.0
CO_2	-37,230.8	-37,230.8
GHG	17,336.3	17,313.1

(GROWTHENERGY1_B4-114)

Agency Response: The GWP values have been corrected to use actual calculated values and eliminates any errors from the use of fixed values. Please see also Response J-5.6d in this chapter.

J-5.6h. Comment: 4. Are there any yeast or enzymes used to produce ethanol from cane? (TD1_26-4)

Agency Response: Yeast is used in sugarcane ethanol production. Since it is re-generated through self-propagation, only a small quantity is required during initiation of fermentation. Staff proposed to include GHG emissions contribution from yeast used in cane ethanol production based on Wang et. al (2012)[46] and it is estimated to be about 0.10 gCO_2e/MJ. No other enzymes are required for sugarcane ethanol production.

J-5.6i. Comment: The emission credit provided for the net (after T&D losses) excess power is the same value as is used for power generation in Brazil. (GROWTHENERGY1_B4-115)

Agency Response: This comment does not require a response.

J-5.6j. Comment: There are a number of other small errors due to the hard coding of truncated GWPs for CO and VOC. There are some inconsistencies between the emissions factors used for this calculator and the starch ethanol calculator for exactly the same activity. (GROWTHENERGY1_B4-122)

Agency Response: Please see Responses J-5.6a and J-5.6d in this chapter.

J-5.7. ***Data Analysis Period***

Comment: We understand that starting in 2021, by March 31st, fuel pathways holders will have to submit to CARB an Annual Fuel Pathway report that contains, among other things, 24 months of data. We have discussed with ARB staff in the past and would like

[46] Wang et al, 2012. "Well-to-wheels energy use and greenhouse gas emissions of ethanol from corn, sugarcane and cellulosic biomass for US use," Environ. Res Lett, 7, 045905. http://iopscience.iop.org/article/10.1088/1748-9326/7/4/045905/pdf.

to reiterate that official sugarcane harvest period in South-Central Brazil is from April thru March[6]. During this time, the majority of mills crush cane up until beginning of December when the intercrop season starts. For those months (December until March), production numbers will likely be zero, and we want to make sure that CARB has fully understood and accepted this nuance/ reality of Brazilian sugarcane ethanol production, without prejudice to the overall analysis of sugarcane ethanol pathway and its carbon intensity score.

6 South-Central region responds for more than 90% of Brazil's sugarcane crush. In North-Northeast region, responsible for less than 10% of national sugarcane crush, the harvest runs from September to August in some states (Alagoas, Bahia, Paraiba, Pernambuco, Rio Grande do Norte e Sergipe) and lasts from May to April in Amazonas, Ceará, Maranhão, Pará, Piauí and Tocantins states.

(UNICA1_127-1, UNICA2_B2-1)

Agency Response: The sugarcane mills in Brazil may report zero production/output during non-production months. The Simplified CI Calculator for sugarcane ethanol can accept zero production entries. The fuel pathway applicant or pathway holder must however report any energy consumed by the mills during non-operating months.

J-5.8. *Straw Emissions and Credits*

Comment: As per previous conversation with CARB staff, we understand that the agency intends to discount electricity credits generated from straw (or sugarcane residues – leftover fibers, stalks and leaves) for all sugarcane ethanol pathways. Our understanding is that the technical basis for such move is the belief that straw removal from the field may influence the need for supplementary use of nitrogenous fertilizers (N-Fert).

We agree that this is an important issue for carbon footprint calculation considering the weight of N-Fert has in the overall GHGs emissions of biofuels. Given the importance of this issue for the LCFS program and for the Brazilian sugarcane ethanol producers, we would like to encourage CARB to do a detailed analysis that better reflect the practice in Brazil, accounting straw emissions and credits in a more complete and in-depth manner prior to making these amendments. In the following paragraphs, we provide an indication of the most relevant literature on the subject.

Vitti et al.[7] (2007) evaluated that Nitrogen (N) and Sulfur (S) stocks of root system are positively correlated with sugarcane yield in the next crop. Figueiredo (2011)[8] indicates that in green-harvested areas, 1619.8 $kgCO2e.ha^{-1}$ are emitted into the atmosphere each year, mainly due to fertilization and diesel use. However, it is worth noting that the results heavily depend on the site-specific characteristics. Fortes et al. (2012)[9] points out those sugarcane post-harvest residues is an important source of carbon and nutrients to soil-plant system. In a recent literature review, Carvalho et al. (2017)[10] argue that the indiscriminate removal of crop residues can reduce the environmental benefits of bioenergy. The same study indicates that benefits in soil carbon (C) stocks

were reduced when total aboveground residue was removed while partial removal of sugarcane residues did not reduce soil C stocks.

[7] Vitti, A.C. et al., (2007). Produtividade da cana-de-açúcar relacionada ao nitrogênio residual da adubação e do Sistema radicular. Pesquisa Agropecuária Brasileira. Brasília, v.42, n.2, p. 249-256.

[8] Figueiredo, E.B. (2011). Greenhouse gas balance due to the conversion of sugarcane areas from burned to green harvest in Brazil. Agriculture, Ecosystems and Environment 141. p. 77-85.

[9] Fortes, C. et al. (2012). Long-term decomposition of Sugarcane harvest residues in São Paulo state, Brazil. Biomass and Bioenergy 42. p. 189-198.

[10] Carvalho, J.L.N. et al. (2017). Contribution of above and belowground bioenergy crop residues to soil carbon. Global Change Biology – Bioenergy.

However, it is recognized that nitrogen from plant residues goes through complex processes, involving several paths to N2O, leaching to groundwater and surface water trapping, as well as direct emissions of the soil as N2O, leaving a small fraction for effective use in the cultivation of the plant. Evidences from Vitti et al. (2008)[11] and Vitti et al. (2011)[12] show that nitrogen from straw does not contribute to sugarcane nutrition and that N from straw is below 1%.

[11] Vitti, A.C. et al., (2008). Mineralização da palhada e crescimento de raízes de cana-de-açúcar relacionados com a aduba- ção nitrogenada de plantio. Revista Brasileira de Ciência do Solo. 32:2757-2762, Número Especial.

[12] Vitti, A.C. et al., (2011). Nitrogênio proveniente da adubação nitrogenada e de resíduos culturais na nutrição da cana- Brasileira. V. 46, n. 3, p.287-293. Brasília – São Paulo, Brasil.

Recent literature corroborates that **there are levels for soil straw removal, with little or no impact on the need for nutrient replacement.** Neto (2015)[13] points out that the presence of different amounts of sugarcane straw did not change N_2O emissions relative to bare soil (control). In an extensive literature review, Carvalho et al. (2016)[14] verifies that crop residues remaining on sugarcane fields provide numerous ecosystem services including nutrient recycling, soil biodiversity, water storage, carbon accumulation, control of soil erosion, and weed infestation. Such agronomic and environmental benefits are achieved when 7 Mg ha^{-1} of straw (dry mater) is maintained on soil surface (about 50% of straw).

[13] Neto, M.S. et al., (2015). Direct N2O emission factors for synthetic N-fertilizer and organic residues applied on sugarcane for bioethanol production in Central-Southern Brazil. Global Change Biology – Bioenergy. Piracicaba, São Paulo – Brazil.

[14] Carvalho, J.L.N. et al. (2016). Agronomic and environmental implications of sugarcane straw removal: a major review. Global Change Biology – Bioenergy. Campinas – São Paulo, Brazil.

We should note that leaving about at least 40%-50% of sugarcane residues on the field leads to a mean annual C accumulation rate of 1.5 Mg ha^{-1} $year^{-1}$ for the surface to 30-cm depth (0.73 and 2.04 Mg ha^{-1} $year^{-1}$ for sandy and clay soils, respectively). It is caused by the conversion from a burnt to an unburnt sugarcane harvesting system, which is the case of the great majority of sugarcane fields in Brazil (Cerri et al, 2011)[15]. This is an additional safety level, once it seems not being captured in the mechanized credits in LCFS.

[15] Cerri, C. C., Galdos, M. V., Maia, S. M. F., Bernoux, M., Feigl, B. J., Powlson, D. and Cerri, C. E. P. European Journal of Soil anic Matters; Volume 62, Issue 1, pages 23–28, February 2011

Considering the above, we suggest that **up to 50% of the straw could be safely removed from sugarcane fields to produce bioelectricity without affecting GHGs**

emissions in agricultural activities. We, therefore, would like to suggest/recommended that the new calculator should have a place to input information of collected straw. This is an extremely important issue for the Brazilian producers and we will be glad to collaborate with CARB to ensure that all nuances of sugarcane ethanol production are captured in the calculator. (UNICA1_127-2, UNICA2_B2-2).

> **Agency Response:** Straw sourced from the same fields which supply sugarcane to a cane ethanol plant in Brazil receive a co-product credit for use to generate process energy and electricity under specific conditions. These include:
>
> a) Emissions for straw collection and transport and displaced fertilizer (to offset removal of straw) must be considered in the life cycle analysis.
>
> b) Non-CO_2 emissions from combustion of straw must be included in the life cycle analysis.
>
> c) No co-product credit will be offered to surplus exported electricity generated from straw combustion since it constitutes 'gearing' and may incentivize electricity generation at the expense of fuel production.
>
> Inclusion of the impacts related to use of straw will complicate the framework of the current Simplified CI Calculator, which would be counter-productive given that the Tier 1 Calculator was developed to simplify and expedite review of cane ethanol pathways.
>
> Analysis of literature for sustainable harvest practices by staff has concluded that harvesting of crop residue (i.e., sugarcane straw, wheat straw, or corn stover) exceeding 25 percent may lead to significant negative impacts related to soil fertility, soil biodiversity, soil water retention, soil erosion, weed infestation control and soil organic carbon (SOC). Staff is, therefore, not permitting the removal of agricultural crop residue to exceed 25 percent for the production of transportation fuel (or blendstocks).[47]

J-5.9. *Mechanization*

Comment: One input in the calculator that is of great importance to the Brazilian sugarcane sector is the mechanization input, given the advances and investments that the industry has made in this front in the last decade and the competitive advantages that set mills apart from their peers.

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[47] This has been LCFS practice for certified fuel pathways involving agricultural residues. See e.g., Certified Fuel Pathway. GranBio Investimentos S.A (6260) Facility Name: Bioflex AgroIndustrial SA (71192). Brazilian sugarcane straw residue-based cellulosic ethanol, with credit for electricity cogeneration and surplus export. https://www.arb.ca.gov/fuels/lcfs/2a2b/apps/gb-102414.pdf; and

Certified Fuel Pathway. Poet DSM Project Liberty LLC (6232) Facility Name: Poet DSM Project Liberty LLC (71164). Corn Stover residue-based cellulosic ethanol with surplus steam and biogas export co-product credits. https://www.arb.ca.gov/fuels/lcfs/2a2b/apps/poet-lib-121715.pdf

According to the State-owned Brazilian Food Supply Company (CONAB in Portuguese), from the Ministry of Agriculture, Livestock and Food Supply (MAPA), the South-Central region, where the majority of UNICA members operate, has reached 95.6% of mechanization level in 2017/2018 crop year, compared to 28,5% one decade ago[16]. Indeed, this index is even higher according the Sugarcane Technology Center (CTC). Following its data, the mechanical harvesting in areas owned by mills, located in South Central region, reached 98% in the named season.

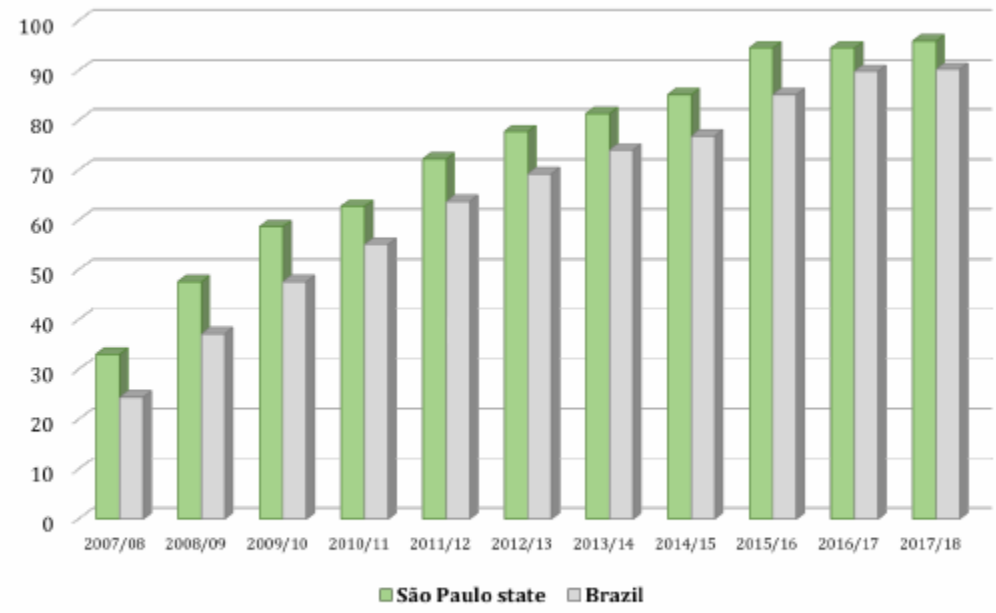
[16] http://www.conab.gov.br/OlalaCMS/uploads/arquivos/17_08_24_08_59_54_boletim_cana_portugues_-_2o_lev_-_17-18.pdf (page 60)

It is important to mention that this is the region responsible for all the ethanol exported from Brazil to countries such as the United States, Japan and the European Union.

As CARB is aware, São Paulo state government, in partnership with UNICA and sugarcane growers association (ORPLANA), created in 2007 a Green Ethanol Protocol, a pioneer initiative that, among other commitments, eliminated pre-harvest field burning in 2017. According to the Environmental Secretary, 95% of all sugarcane processed in the São Paulo state is under the management of certified parties.[17] Since June 2017 this commitment has entered into a new phase, now called More Green Ethanol Protocol, that continues to reiterate the pre-harvest field burning commitment, but includes the important commitment of restoring riparian vegetation around cane fields.

[17] Slide 3 of the document: http://arquivos.ambiente.sp.gov.br/etanolverde/2017/06/etanol-verde-relatorio-preliminar-safra-16_17-site.pdf

Sugarcane Harvesting– Fast Mechanization Process in Brazil



Source: CONAB (National Supply Company, from the Brazilian Ministry of Agriculture, Livestock and Food Supply

As previously mentioned, industry has invested a great deal in mechanization in the sector in the last decade. Investments that helped sector reach a level of 57% of GHG emissions reduction from harvesting over the past 10 years (from 4.8 to 2.1 g CO_2eq/MJ of ethanol), considering the parameters given in Table 1. We believe there is strong evidence that the soil carbon stocks increase due to unburned mechanized harvesting[18]. Estimations from Figueiredo and La Scala Jr (2011)[19] indicate that the emissions in the mechanized harvesting are almost 1500 kg CO_2eq ha^{-1} $year^{-1}$ lower than those for the burned harvesting, since it leads to a soil carbon sequestration of more than 1170 kg CO_2eq ha^{-1} $year^{-1}$.

[18] Cerri, C. C., Galdos, M. V., Maia, S. M. F., Bernoux, M., Feigl, B. J., Powlson, D. and Cerri, C. E. P. European Journal of Soil Science; Special Issue: Soil Organic Matters; Volume 62, Issue 1, pages 23–28, February 2011

[19] Figueiredo EB, La Scala Jr N. Greenhouse gas balance due to the conversion of sugarcane areas from burned to green harvest in Brazil. Agriculture, Ecosystems and Environment 141 (2011): 77-85.

Table 1: Parameters used for the estimation of emissions balance between burned and mechanized harvesting

Parameter	Value/source
% Mechanized harvesting	CONAB
Sugarcane production	UNICA[20]
Sugar and ethanol production	UNICA[20]
Straw burning emissions	2.7 kg CH_4/t dry matter burnt[21]
	0.07 kg N_2O/t dry matter burnt[21]
Straw to cane stalk ratio	140 kg (dry basis) per tonne of stalk[22]
Harvester's diesel consumption	74 L/ha [23]
Life cycle diesel emissions	83.8 g CO_2eq/MJ [24]

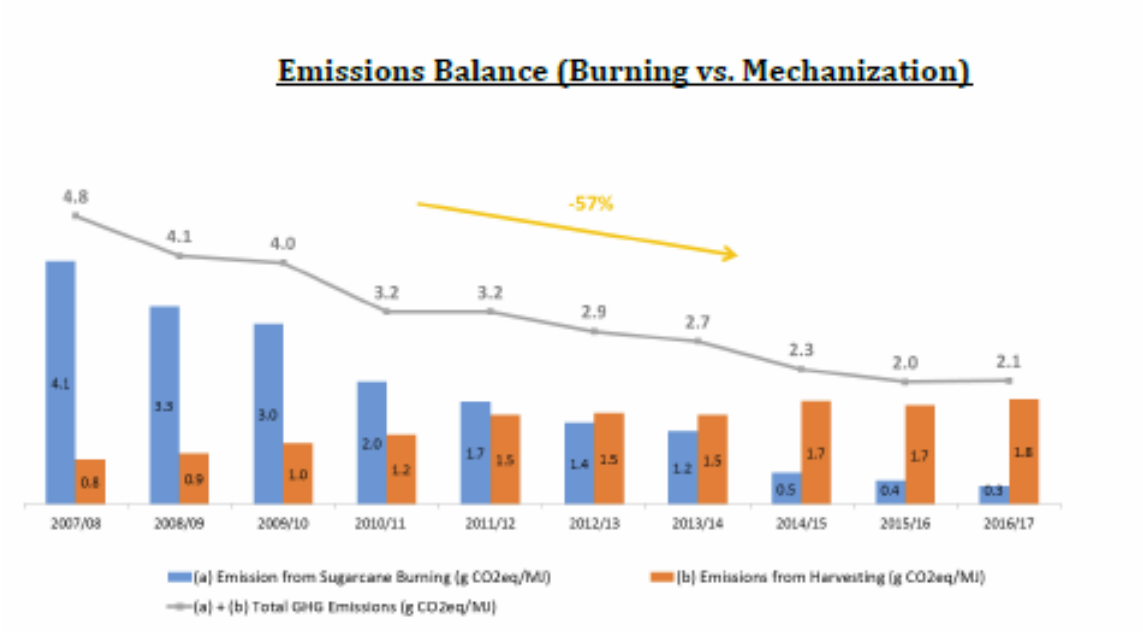
[20] http://www.unicadata.com.br/

[21] IPCC 2006, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Prepared by the National Greenhouse Gas Inventories Programme, Eggleston H.S., Buendia L., Miwa K., Ngara T. and Tanabe K. (eds). Published: IGES, Japan.

[22] Hassuani SJ, Leal MRLV, Macedo IC. Biomass power generation: sugar cane bagasse and trash. Piracicaba: PNUD Brasil and Centro de Tecnologia Canavieira; 2005.

[23] Adapted from Macedo IC, Seabra JEA, Silva JEAR. Green house gases emissions in the production and use of ethanol from sugarcane in Brazil: The 2005/2006 averages and a prediction for 2020. Biomass and Bioenergy 32 (2008): 582- 595.

[24] European Parliament and Council of the European Union, Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009, on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC, Official Journal of the European Union of 5 June (2009).



In the CI calculator for sugarcane ethanol, CARB proposes two default values for sugarcane mechanization for Brazil: 80% for São Paulo state and 65% for other states in the Center-South region. By choosing to use the default values, mills will not need to have this input verified. UNICA will probably have members who will be satisfied using the default value, however, the vast majority of our members located in Sao Paulo, who have nearly all of its sugarcane harvesting mechanized, prefers to prove that they are at highest level, as abovementioned reported by CONAB and CTC.

For this effect, UNICA would like to request that CARB includes an option for self-declared mechanization percentage in the CI calculator, and that mills opting for it will have its data and its mill audited by a CARB authorized third party verification body. In Exhibit A we suggest an outline for proving sugarcane mechanization levels in Brazil. In sum we propose that Brazilian mills be given three options: 1) using the default values proposed by CARB and forgo verification of this input; 2) self-declare and go through verification via auditing of its production record/mill; and 3) use of satellite imaging to show the levels of mechanization and go through the verification process of its records/mill. WE believe that any certification plan CARB develops for proving mechanization levels of Brazilian sugarcane ethanol mills should follow along these lines.

UNICA member mills are highly sophisticated enterprises who invest a great deal in the automatization of their agricultural and industrial processes. Third party verifying bodies in Brazil have for years audited mills' systems for certification schemes like the Bonsucro, EPA's RFS program and the LCFS in itself. We encourage CARB staff to continue to reach out to verification companies in Brazil in order to clarify doubts or misunderstanding regarding the automatized systems used by sugarcane mills.

We believe providing these options are not only the best way to capture the reality of sugarcane mechanization practices in Brazil, but it is also the fairest approach.

…

PARAMETERS FOR MECHANIATION METHODOLOGY

The following methodologies will be acceptable for applicants to apply for mechanization percentage:

1. Default Values

    a) State of São Paulo: standard mechanized harvesting level of 80%

    b) Non – São Paulo States: standard mechanized harvesting level of 65%

2. Site Specific (Self-declared) – all option require third party verification

    a) Mills with AUTOMATIC SYSTEM for sugarcane information registration should comply with the following parameters:

        - At least 80% of sugarcane volume should be automatically registered in the system.

            - If higher than 80%, mills should go through an audit process to validate the results from burned and raw sugarcane quantity registration.

Audit for mechanization verification to be performed by a third party verifier previously authorized and registered with CARB. Verification to include:

- Auditor to previously request automatically-generated cut orders (for both own and outsourced cane) for the time period in question

- Auditor to previously request all agricultural reports produced by the mills' automated system (PIMS, GATec, SAP, ERP, etc) for the time period in question

- For mills in the State of Sao Paulo, auditing team to request the Authorization certificates for Legal Burning of Sugarcane from the Environmental Company of the State of Sau Paulo (CETESB), if any planned burning is reported

- Auditing team to request any information regarding accidental and/or criminal burning, and verify all documentation registered in the system

(UNICA1_127-3, UNICA2_B2-3)

Agency Response: Staff supports the efforts of the industry overall to move toward mechanized harvests. However, at this time, verifying mechanized harvest percentage for every applicant imposes a significant burden and increased costs on third-party verifiers to develop expertise with GIS and similar

tools. Therefore, to expedite review and validation (and ongoing verification) of cane ethanol fuel pathways, staff proposed two specific levels of mechanized harvest fractions which are exempt from verification. These two levels specified provide reasonable assurance of accuracy without the explicit demonstration of harvest levels, expediting initial review and ongoing verification.

To consider the commenters request to account for mechanization exceeding 80 percent, staff completed an estimation of potential benefits attributable to increased percentage of mechanization. Using representative data for pathway applicants under CA-GREET3.0, staff has estimated that a net benefit is less than 1.0 gCO_2e/MJ when 95% mechanization is considered. This potential small benefit in pathway emissions to individual cane ethanol pathways will require significant expertise and resource requirements for both staff and third-party verifiers to confirm marginal improvements in mechanized harvesting.

Therefore, staff will not consider the carbon sequestration impact of mechanized harvesting and provisions to include mechanization levels beyond the two options offered in the Simplified CI Calculator. During a future rulemaking, updates to mechanization rates will be evaluated based on published and verifiable data for sugarcane harvest practices in Brazil from national and international bodies. This is generally consistent with the approach to ag-phase emission reductions taken by staff for corn ethanol.

While staff is aware of the possibility of carbon sequestration in sugarcane farms due to sustainable mechanized harvesting, the science on quantification of soil carbon sequestration is not settled yet. In addition, permanence of sequestered carbon is not guaranteed since carbon can be released due to any changes in agriculture practices and land use in the future. At this time, CARB does not have a regulatory framework to ensure longer-term permanence of the sequestered soil carbon. As with mechanized harvesting, updates to carbon sequestration will be evaluated based on published and verifiable data for harvest practices from national and international bodies.

J-5.10. *Ethanol Pipelines*

Comment: We would like to request CARB staff to include a pipeline transportation option in the CI Calculator for sugarcane ethanol. Although this modal of transportation is still less prominent than truck in Brazil, it is certainly a trend for the near future, as it represents a unique infrastructure that ensures fast, sustainable and low-cost transportation. We believe the addition of this option in the calculator is crucial in order to benefit mills who decide to use it to gain competitiveness in the California market.

Investments in integrated ethanol storage and distribution systems through pipelines, such those made by our member companies Copersucar, Raizen and Atvos in partnership with other stakeholders to create Logum Logística S.A., are a reality.

Ethanol transport through pipelines uses the LOGUM and Transpetro Pipelines systems which operate with hydrous and anhydrous ethanol, gasoline and diesel. In total these pipelines together can extend to 950 Km (590 miles).

Source: Logum System

We understand CARB is concerned with potential contamination of the product given that these pipelines are not for exclusive use of ethanol. For this same reason, and because ethanol producers need to guarantee the quality of their product to their buyer, quality control practices in pipeline transportation are extremely strict.

In summary, the process of ethanol transportation in pipelines occurs as following: fuels are transported in parcels; the flow is continuous and under pressure, allowing for the existence of a contact zone among the fuels, called “interface”. The interface between hydrous and anhydrous ethanol does not impact the technical specification of the products, as per the National Agency of Petroleum, Natural Gas and Biofuels’ (ANP) requirements.

In the case of ethanol and gasoline interface, ANP has particular requirements to protect the quality of both fuels. This control refers to a product certification in all phases of the transportation, and this is done via automated process, controlling the flows of fuels not to exceed the requirement’s limits. It is important to clarify that, in order to guarantee quality control, ethanol fuel is inspected before leaving the port in Brazil and at arrival in the destination port.

When the pipeline moves diesel, it necessarily has to move gasoline in the sequence because this fuel works to seal the pipeline, allowing for the transport of ethanol without any modification. A small loss of 0,2% is allowed, which is normally due to evaporation. ANP exercises strict control and verification of product quality and specification and the flow of fuels have been taking place without any known quality control incident.

For illustration and clarification purposes we would like to share with staff, in Exhibit B, a paper that addresses the methodology of quality control in pipeline transportation in Brazil. We hope this gives staff a better understanding of how the process works in the country. We urge staff to provide this modal of transportation option in the CI calculator, and we remain at staff's disposal to answer any question and to connect CARB with the right people in order to provide better understanding of this issue. (UNICA1_127-4, UNICA2_B2-4)

> **Agency Response:** Staff used the CA-GREET3.0 calculator to evaluate differences in emissions between truck and pipeline transport of ethanol within Brazil. The analysis determined that changes in CI when considering pipeline transport (inclusive of modest truck transport to pipeline locations) are below the substantiality threshold. Staff proposes that applicants must use their current truck transport distances in their pathway applications to reflect conservative CIs for their fuel pathways. No changes will be made to offer this option in the Simplified CI Calculator.

J-5.11. *Maritime Transportation*

Comment: Unfortunately CARB has brought back the notion of back-haul penalties for maritime transportation of sugarcane ethanol to California. It is unknown to us that CARB has obtained data to support its assertion that ocean tankers bringing ethanol fuel from Brazil to California will necessarily return to Brazil, and empty. From conversations with staff we understood that this back-haul emission penalty is due to a conservative approach staff wants to take in case this happens in the future. We decided to verify our observations that ethanol ships from Brazil do not return empty and would like to present our findings to staff in Exhibit C.

In the past two years, nine ships have brought ethanol from Brazil to California, for a total of 10 trips (vessel High Valor has made the trip twice), from California these vessels called other ports to deliver other products. The tracking of these vessels confirmed our observations that ships do not necessarily go back to Brazil, and certainly not empty. Out of 10 trips, only one was back to Brazil, with the vessel carrying diesel. All other nine trips were to Asia, Europe and Mexico.

Maritime transportation would certainly not be efficient and affordable if vessels would travel empty around the world. Assuming that the energy consumption and associated emissions of the ocean tanker's round trip be attributed to sugarcane ethanol is highly speculative and arbitrary and causes a tremendous impact in sugarcane ethanol competitiveness in the California market. We would like to request that staff do not consider the emission of shipments returning to Brazil, since it defers from current market and trading practices. In the images bellow it is possible to compare the impact of the methodology change in terms of CI impact. If we consider the same distance parameter compared to CA-Greet 2.0 and CA-Greet 3.0, the CI impact is almost 4 gCO2e/MJ:

CA-Greet 2.0

Transportation and Distribution			5,88
From ethanol plant to port	HDD Truck		
Shares	100%		
Miles			
From ethanol plant to port	Pipeline		
Shares	100%		
Miles	0		
From ethanol plant to port	Rail		
Shares	100%		
Miles	0		
From port to CA port	Ocean Tanker		
Shares	100%		
Miles	8,953		
From CA port to blending terminals	HDD Truck		
Miles	40		
From terminals to fueling stations	HDD Truck		
Miles	50		

CA-Greet 3.0

Ethanol Transport and Distribution			9,73
From Ethanol Plant to Brazil Port	Mode: HDD Truck	6884284.2850647 dry gals	
Miles	0		
From Brazil Port to California Port	Mode: Ocean Tanker	100%	
Miles	8,953		
From California Port to Blending Terminal	Mode: HDD Truck	100%	
Miles	40		
California Blending Terminal to Refueling Station	Mode: HDD Truck	100%	
Miles	50		

(UNICA1_127-5, UNICA2_B2-5)

Agency Response: Please see the second paragraph in the response for UNICA3_FF38-2 in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

J-5.12. *Carbon Intensity Score for Sugarcane Ethanol*

Comment: We urge CARB to consider our suggestions and ensure that sugarcane ethanol is fairly scored in the GREET-CA 3.0 modeling and that Californian consumers reap the benefits of sugarcane ethanol. (UNICA1_127-7, UNICA2_B2-7)

Agency Response: We thank the commenter for their feedback.

J-5.13. *Farming Energy*

Comment: 1. What is the farming energy in Ca GREE2.0 for sugarcane? It would probably be different for 80% mechanized than 65% mechanized, correct?

But if mechanized, there would be some diesel fuel use, so I expected to see some energy use in BTU/ton of cane. (TD1_26-1)

> **Agency Response:** The farming energy associated with sugarcane harvesting reflects a mechanized harvesting level of 80 percent (Wang et al, 2011).[48] For mechanized harvesting levels lower than 80 percent, the same farming energy use is used to model emissions since it represents an upper bound as more diesel fuel is expended with higher levels of mechanization.

J-5.14. *Nitrogen in N_2O*

Comment: 3. What "N in N2O" percentages are being used in CaGREET3.0 for cane? I note that it is 1.325% for crop residue for corn, and 1.225% for fertilizer for corn. Is it the same numbers in CaGREET3.0 for cane? It is not in Table 26. (TD1_26-3)

> **Agency Response:** To ensure consistency, staff has updated the CA-GREET3.0 model to reflect 1.325 percent as the value for all crop residues.

J-6. *Biodiesel and Renewable Diesel Carbon Intensity Calculation*

J-6.1. Comment: Several hidden rows exist on the biodiesel and renewable diesel production sheets that have calculations which are not being used. There are also 18 hidden sheets in the calculator. A number of cells on the reference sheet that take their values from a "User Defined" sheet. They are in several rows that are hidden, and they only go forward to the hidden LFG sheet. These hidden sheets should be removed if they do not impact the model, and any that are required should be unhidden to improve the transparency of the model.

Multiple errors exist in the biodiesel and renewable diesel Simplified Calculator. Most of them are on the renewable diesel calculator sheet—one is large, but the rest result in small errors. The errors generally result in calculated emissions that are lower than they should be. There are also some fixed values used by CARB that are not in the existing calculators or result in the double-counting of real world emissions. The issues are documented below. (NBBCABA1_29-13)

> **Agency Response:** The Biodiesel and Renewable Diesel (BD/RD) Simplified CI Calculator posted online on March 6, 2018, does not include any of the hidden rows, calculations, or hidden sheets.

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[48] Wang et al, 2012. "Well-to-wheels energy use and greenhouse gas emissions of ethanol from corn, sugarcane and cellulosic biomass for US use," Environ. Res Lett, 7, 045905 (Table 2). http://iopscience.iop.org/article/10.1088/1748-9326/7/4/045905/pdf

Responses to errors in this calculator are addressed in Responses J-6.5 through J-6.16 in this chapter.

J-6.2. Comment: There is a fixed value of 0.03 g/MJ for UCO collection that is separate from UCO transport that was not in the CA GREET 2.0 Tier 1 calculator. This is a fixed value independent of any user input. It appears to derive from some type of electricity. If so, where is the documentation? It is our view that undocumented emissions should not be included in the simplified calculator. They are not in the tallow pathway.

Appendix C states that the UCO collection energy is the same as CA GREET 2.0, but this is not the case. (NBBCABA1_29-14a)

Agency Response: The comment is out of scope since this value does not exist in CA-GREET3.0.

J-6.3. Comment: BD Production UCO: H119 multiplies by F184 instead of dividing by F184, it should be:

H119=F119*J119/2000/$F$118/$F$184*$C$48*$E$246

(NBBCABA1_29-14b)

Agency Response: Cell F184 refers to biodiesel yield (lbs. BD/lb. oil). Staff has corrected the calculation to reflect the intended use of this factor.

J-6.4. Comment: There are no collection emissions for tallow. This should also be the case for UCO. (NBBCABA1_29-16)

Agency Response: For standard UCO collection by a renderer, there are no attributable emissions to feedstock collection. However, for entities who source UCO directly to their facility (non-rendered), a fuel producer may choose collection routes which entail additional feedstock transportation impacts compared to direct transport to the nearest renderer. To ensure such impacts are accounted in the CI of the finished fuel, transport distance for local sourcing of non-rendered UCO is a required input in the Simplified CI Calculator.

J-6.5. Comment: BD Production Tallow: M141, M154, M155, M156, M157 should use B85 off of Fuel Specs instead of B83. Currently B83 and B85 are the same value, but that could change in the future. (NBBCABA1_29-17a)

Agency Response: The cells mentioned above include loss factors for various feedstocks used in biodiesel production. The Calculator uses the same loss factor of 1.00003866 for all feedstocks. In the future, if data supports the use of feedstock specific factors, the CA-GREET model will be appropriately updated.

J-6.6. Comment: BD Production Tallow: H140 has the same issue as UCO H119. It should be:

H140=F140*J140/2000/$F$139/$F$184*$C$48*$E$249

(NBBCABA1_29-17b)

Agency Response: Cell F184 refers to biodiesel yield (lbs. BD/lb. oil). Staff has corrected the calculation to reflect the intended use of this factor.

J-6.7. Comment: The most significant error is in cell I208 on the RD Production sheet. The formula is:

=H208/$C$51*References!$C$116/Fuel_Specs!$B$18*10^6

It should be this: =H208/$C$51/Fuel_Specs!$B$18*10^6

The CARB value takes the gallons of renewable diesel, converts it to pounds and then uses the energy content per gallon to arrive at the total emissions avoided. The value is too high by a factor of 6.5 (the pounds of RD per gallon). The result is an exaggerated co-product credit for renewable diesel. (NBBCABA1_29-18)

Agency Response: Density of renewable diesel (Cell References!$C$116) was inadvertently included in the equation to convert gallons to pounds. Staff has corrected this calculation.

J-6.8. Comment: There are some small inconsistencies in the ratio of the results for the renewable diesel pathway to the biodiesel pathway. This is shown in the following tables.

The first table shows the emissions for a given set of inputs for the fuel production stage for each feedstock. As should be the case, all of the values are the same for each feedstock and the ratios of the biodiesel and renewable diesel values are constant.

Feedstock	Biodiesel Fuel Production	Renewable Diesel production	Ratio RD/BD
Soy oil	9.63	10.27	1.0665
Canola Oil	9.63	10.27	1.0665
Corn Oil	9.63	10.27	1.0665
UCO	9.63	10.27	1.0665
Tallow	9.63	10.27	1.0665

When the same calculation is done for the feedstock the ratios are all different. Unlike the fuel production values, the feedstock emissions should not be the same for all of the feedstocks. But since the feedstock emissions should be scaled by the energy efficiency of the process, the ratios of the feedstock emissions should be the same. In

two cases, soy oil and corn oil, the ratios are the same, but that is not the case for the other feedstocks.

Feedstock	Biodiesel Fuel Production	Renewable Diesel production	Ratio RD/BD
	g CO_2/MJ		
Soy oil	13.65	13.49	0.9881
Canola Oil	22.75	22.42	0.9856
Corn Oil	12.94	12.79	0.9881
UCO	5.74	5.49	0.9563
Tallow	18.27	17.20	0.9413

Every single stage should come out to 0.98811. Working through the calculations identified the following errors in the calculator.

- RD Production Soy Oil: M59 and M60 are incorrectly pulling B79 off fuel specs instead of D79. B is BD and D is RD. (NBBCABA1_29-19a)

  Agency Response: Staff has corrected calculations to address this comment.

J-6.9. Comment: RD Production Soy Oil: J74 to J77 are static numbers rather than being linked to the same numbers on EF Table sheet. (NBBCABA1_29-19b)

Agency Response: Staff has addressed this error by updating the links for cells J74 to J77 to reflect inputs from the EF Table sheet.

J-6.10. Comment: RD Production Canola Oil transport errors: F96, F97, F98 are referring to the wrong columns. Should be I, K, M respectively. (NBBCABA1_29-19c)

Agency Response: Staff has corrected the errors as indicated above.

J-6.11. Comment: RD Production Canola Oil: M81 and M82 are missing the F80 yield factor. (NBBCABA1_29-19d)

Agency Response: Staff has included a yield factor to correct this error.

J-6.12. Comment: RD Production Canola Oil: H81 and H82 are calculated completely differently from both their equivalents on BD production and from H80. They should be:

H*1=F81*J81/$F$80/Fuel_Specs!$D$53/$F$189*$C$52*$E$255
H82=F82*J82/$F$80/Fuel_Specs!$D$53/$F$189*$C$52*$E$255

(NBBCABA1_29-19e)

Agency Response: Staff has corrected both cells to reflect the intended calculations. The updated calculations are:

H81 = F81*J81/$F$80/Fuel_Specs!$D$53/$F$178*$C$52*$E$244
H82=F82*J82/$F$80/Fuel_Specs!$D$53/$F$178*$C$52*$E$244

J-6.13. Comment:

- RD Production Corn Oil: M102, M103, M115, M116, M117, and M118 are all pulling D83 off of fuel specs instead of D87. D83 is UCO BD not Corn Oil BD.
- RD Production UCO: M121 uses B83 off of fuel specs instead of D83.

(NBBCABA1_29-19f)

Agency Response: Staff has corrected links for cells M102, M115, M116, M117, M118, and M121 to appropriate cells in the Fuel_Specs Tab. Cell M103 mentioned by the commenter is an empty cell and is, therefore, not relevant.

J-6.14. Comment:

- RD Production UCO: H122 has an incorrect math operation as was the case for BD. It should be:

  H122=F122*J122/2000/$F$121/$F$189*$C$52*$E$257

- RD Production Tallow: M143 should use D85 off of fuel specs instead of D83
- RD Production Tallow: H143 has an incorrect math operation as was the case for BD. It should be:

  H143=F143*J143/2000/$F$142/$F$189*$C$52*$E$260

(NBBCABA1_29-19g)

Agency Response: Staff has corrected the error in cell H122, and the updated equation is provided below:

H122 = F122*J122/2000/$F$121/$F$178*$C$52*$E$246.

Staff has corrected the error in cell H143, and the updated equation is provided below:

H143 = F143*J143/2000/$F$142/$F$178*$C$52*$E$249.

Staff has corrected the link for cell M143.

J-6.15. Comment: RD Production Tallow: D150 and D162 are switched. The distance and the emission factors are correct if the labels are reversed. (NBBCABA1_29-19h)

Agency Response: For clarity, staff has marked Cell D150 to refer to transportation of rendered tallow by barge. Cell D162 is an empty cell and the comment is, therefore, not relevant.

J-6.16. Comment:

- RD Production: Cells H197 and H201 have an incorrect reference. They should be

  F197*J197***$C$52***Fuel_Specs!$B$79/Fuel_Specs!$F$69

Making these corrections now provides the same ratio of renewable diesel to biodiesel feedstock emissions for each feedstock, as should be the case. (NBBCABA1_29-19i)

> **Agency Response:** Staff has made the appropriate correction to Cell H197 and deleted cell H201 since it is not relevant to this Calculator.

J-6.17. Comment: There are a significant number of inconsistencies on the emission factors that are used for the different products. While these all arise from GREET 2016 values, they clearly do not reflect industry practice or the current knowledge concerning energy use in transportation. (NBBCABA1_29-20)

> **Agency Response:** Argonne researchers use multiple sources to include peer-reviewed literature, process engineering journals, publications from the Department of Energy and industry partners to develop emission factors for their life cycle analysis model. These factors are complemented using data available from review of hundreds of pathway applications by staff from 2011 through 2017. Staff is confident that emission factors in CA-GREET3.0 reflect current industry practice including energy use in transportation. Staff does not agree with commenter that inconsistencies exist in emission factors used in the CA-GREET3.0 model.

J-6.18. Comment: The emission factors for soybeans and canola seeds are compared in the following table.

	Soybeans		Canola
	gCO_2e/ton-mile	gCO_2e/metric ton-mile	gCO_2e/metric ton-mile
MDT	352.70	387.97	371.69
HDT	370.24	407.26	390.18
Rail	31.50	34.65	33.20
Barge	85.41	93.95	90.07

It is not clear why the soybean transportation energy use is 4.4% higher than the canola values. (NBBCABA1_29-21)

> **Agency Response:** The energy use values are different because the standard moisture contents for canola (9 percent) and soybean (13 percent) are different in the CA-GREET3.0 model.

J-6.19. Comment: In CA GREET, they have the same energy use per ton-mile. It is also not logical that the energy use is lower for a medium-duty truck than it is

for a heavy-duty truck. CA GREET appears to have overestimated the fuel use for a heavy-duty truck and underestimated the fuel use for a medium-duty truck compared to the most recent values in the Oakridge National Laboratories Transportation Energy Use Data Book[12].

[12] Transportation Energy Data Book. https://cta.ornl.gov/data/index.shtml.

	CA GREET	Transportation Energy Use Data Book
	Miles per gallon	
MDT	10.4	7.4
HDT	5.3	5.9

(NBBCABA1_29-22)

Agency Response: In consultation with researchers at Argonne, staff used updated fuel economy and energy consumption for medium heavy-duty trucks (MHDT) and heavy heavy-duty trucks (HHDT) as detailed in the table below. Argonne researchers communicated to staff that the values for truck transport used in the GREET model was based on substantive discussions with industry, the Department of Energy, USDA and other relevant stakeholders. Staff, therefore, will use the values as detailed below. If in the future, Argonne address such comments and refines these values in their model, staff will consider updating these in a future rulemaking.

	Fuel Economy (miles/diesel gallon)		**Energy Consumption (Btu/mile)**	
	Heavy Heavy-Duty Truck	Medium Heavy-Duty Truck	Heavy Heavy-Duty Truck	Medium Heavy-Duty Truck
Trip from Product Origin to Destination	7.3	8.3	17,596	15,476
Trip from Product Destination Back to Origin	9.2	8.9	13,962	14,433

J-6.20. Comment: In addition to the energy use being questionable, the load size is too small for the heavy-duty truck at only 15 tons. While the maximum load size will vary by state, a typical value is 20 tons for a heavy-duty truck. The model also uses the same energy per ton-mile for an empty trip as a fully loaded trip. This is incorrect as the empty energy use should be about half of the fully loaded energy use—the difference in weight between an empty and fully loaded truck.

All of the rendered oils use the same emission factors, but they can be compared to the values for oilseeds as shown below. They are all lower. The load size for a HDT for rendered oil is 25 tons vs the assumed 15 tons for oilseeds.

	Rendered Oil	Soybeans	Canola
	gCO_2e/ metric ton-mile	gCO_2e/ metric ton-mile	gCO_2e/ dry metric ton-mile
HDT	212.59	407.26	390.18
Rail	30.14	34.65	33.20
Barge	81.73	93.95	90.07
Ocean tanker	38.28		

(NBBCABA1_29-23)

Agency Response: Payload and fuel economy for MHDT and HHDT is updated to reflect Argonne's update in their model. Payload for truck transport has been updated to 20 tons. These updates also address differences in emissions for a fully loaded and empty truck transport (please see Response J-3.18 in this chapter).

J-6.21. Comment: Finally, CA GREET assumes a different size for the ocean vessel for biodiesel and renewable diesel compared to the rendered oil. Those emission factors are compared in the following table. This would put California producers who import feedstock at a disadvantage to out-of-state producers who can ship by ocean vessel.

	Rendered Oil	BD	RD
	gCO_2e/metric ton-mile		
HDT	212.59	213.04	213.04
Rail	30.14	30.21	30.21
Barge	81.73	81.90	81.90
Ocean tanker	38.28	20.08	20.08

(NBBCABA1_29-24)

Agency Response: Changes in ocean vessel sizes were included to reflect data from pathway applications. When applicants model feedstock and finished fuel transport specific to their pathway, it may disadvantage certain producers seeking feedstocks distant from their production facilities. The modeling framework however, is equitable to all producers and requires fuel pathway applicants to declare appropriate transport modes and distances in their pathway applications. The regulation does not seek to disadvantage any producer but rather to accurately account for CI for fuel based on relevant pathway inputs to the CA-GREET3.0 model.

A comparable situation exists for starch ethanol producers in California who source corn from distant markets in the Mid-Western United States. Higher emissions for feedstock transport is offset by lower emissions for finished fuel transport. Some in-state ethanol producers who compete with out-of-state starch ethanol producers have done so favorably since the initiation of the LCFS

program. Therefore, there is no merit in stating that in-state producers may be disadvantaged by out-of-state producers electing to use cost-effective (and potentially with lower emissions) modes of transport. The LCFS uses a carbon intensity metric to differentiate between fuels and does not discriminate solely based on geographic location.

J-6.22. **Comment:** The higher energy intensity for barge transportation than for rail is not supported by the literature. Again, this could be the result of old data that has not been updated. The rail and domestic water energy use in CA GREET is compared to the data from the Transportation Energy Data Book in the following table.

	CA GREET	Transportation Energy Use Data Book
	BTU/ton mile	
Rail	274	292
Barge	735	214

In both cases the methodology is to take the total energy consumption for the mode and the total ton-miles of freight moved. This automatically accounts for the "back-haul" and there is no need to add additional energy for this movement as is done in CA GREET. It appears that the barge transport emission factor in CA GREET is too high by a factor of 3.4.

This is confirmed by the recent National Academies publication "Funding and Managing the U.S. Inland Waterways System: What Policy Makers Need to Know (2015)". In appendix G[13] it is stated that:

> Some studies show barge to be more energy efficient, while others show rail as the more energy-efficient mode. In term of British thermal units per ton-mile, Davis et al. report that rail (294 Btu/ton-mile- in 2012) is 40 percent more energy intensive than barge (210 Btu/ton-mile in 2012), nearly the same percentage difference as reported by Kruse et al. (2013). These average energy intensity values represent the two-way transport average of upstream and downstream transport (upstream transport may require more energy to account for barge movement against downstream current velocities, and downstream transport energy may benefit from the river current). Alternatively, Dager (2013) reports even lower energy intensity for inland barge transport on the basis of independent data and fuel use modeling corresponding to about 196 Btu/ton-mile, or about 60 percent better energy intensity than average rail.

[13] Appendix G. https://www.nap.edu/read/21763/chapter/15

(NBBCABA1_29-25)

Agency Response: In consultation with experts from Argonne and other research institutes, staff has updated the energy intensity of the barge transportation mode to 223 Btu/ton-mile, which accounts for both up-bound and down-bound trips.

J-6.23. **Comment:** The emission factors for biomass and renewable natural gas (cells 45 and 35) are too high. They do not recognize the biogenic nature of the combustion emissions. Both values are used on the renewable diesel production sheet although other inputs that would be required to use the emission factors are missing. (NBBCABA1_29-26)

> **Agency Response:** Staff has deleted emission factors for landfill gas and biomass from the EF Table. Facilities which use LFG and biomass as process fuels will need to consult with staff to develop site specific emission factors for such sources.

J-7. *Corn Oil Credit Calculation*

J-7.1. Multiple comments: *Corn Oil Credit Calculation*

Comment: Corn oil credit calculation in the calculator continues to perpetuate the corn oil energy accounting issue. The following table presents the current status and two different options to address the issue.

Options	Extraction energy treatment	Corn oil treatment
Current	Double counts extraction energy in Ethanol pathway	As DGS mass
Proposed	Allocate power to starch EtOH and Corn Oil on energy basis	DGS mass
More Accurate	Allocate all energy inputs to both products	Allocate ILUC (for corn and DGS credit) to both products

As per the discussions between ARB and Life Cycle Associates during February 2018, the solution to mitigate the double counting is to allocate the electricity consumption between the corn oil and the corn ethanol produced weighted by their corresponding total energy content. (LCA1_8-1)

Comment: Allocating electric power used by the ethanol plant to corn oil and starch ethanol based on the energy content of each product is a reasonable approach in the interim until the distribution of ILUC to ethanol and corn oil can be evaluated. Both the ethanol plant operations and corn oil extraction both require electric power. Determining the power requirement for each operation would require additional data collection which is not warranted. Furthermore, allocating the roughly 0.5 kWh to 1 kWh of power per gallon of ethanol to both ethanol and corn oil yield provides a GHG savings to the ethanol plant that is comparable to the extraction addition in the corn oil biodiesel pathway. ARB could also align the extraction burden in the corn oil biodiesel pathway with the average data from corn ethanol plants that have registered under the LCFS. (LCA1_8-3)

Comment: Soy oil ILUC directly related to ILUC from Soy BD pathway. ILUC calculations take into account SO to BD yield. Soy bean density and allocation factors

are also part of the calculation. ILUC calculations for SO and SBM are referred to as Method 1S in the analysis.

This method involves the soy oil and soybean meal as the only products of soybean. This method simply gives us the ILUC of soybean mean and soyoil based on the BD ILUC, and the relevant yields and allocation factors. (LCA1_8-10)

Comment: Corn oil used for BD or animal feed diverts the corn oil from the DGS mass. This reduces the DGS that is produced and thus the ILUC credit for DGS should also be lowered.

ARB GTAP ILUC analysis took into account the substitution of corn, soybeans, and other agricultural products. The GREET substitution ratios provide basis for estimating ILUC portion of DGS and corn separately. (LCA1_8-11)

Comment: Method 1 combines the GREET substitution ratios with GTAP ILUC results for corn ethanol and soy biodiesel and builds on Method 1S. This allows the calculation of the ILUC for corn and DGS separately. (LCA1_8-12)

Comment: Corn and soybean yields combined with GTAP ILUC for corn ethanol provide basis for determining ILUC of DGS, corn, and soybeans. This method assumes that an acre of land can grow either corn or soybeans. The ILUC of corn, DGS and soybeans is determined based on the relative yields of the crops with ethanol ILUC as the fixed starting point.

Table 1. ILUC Calculation Results

Parameter	Method 1s	Method 1	Method 2
M_{CORN} (kg corn/bu corn)		25.40	25.40
M_{EtOH} (kg EtOH/bu corn)		8.13	8.13
M_{DGS} (kg DGS/bu corn)		6.95	6.95
M_{SB} (kg soybean/bu soybean)	27.22	27.22	27.22
M_{BD} (kg biodiesel/bu soybean)	5.23	5.23	
M_{SBM} (kg soybean meal/bu sb)	21.77	21.77	21.77
M_{SO} (kg soyoil/bu soybean)	5.44	5.44	5.44
$iluc_{EtOH}$ (gCO_2e/kg EtOH)		533.6	533.6
$iluc_{BD}$ (gCO_2e/kg BD)	1,092.1	1,092.1	1,449.8
$iluc_{SBM}$ (gCO_2e/kg SBM)	1,050.0	1,050.0	1,393.9
$iluc_{CORN}$ (g CO_2e/kgcorn)		329.4	443.2
Back Calculate:			
$iluc_{DGS}$ (gCO_2e/kg DGS)		579.8	995.5
$iluc_{SB}$ (gCO_2e/kg SB)	1,050.0	1,050.0	1393.9
$iluc_{SoyOil}$ (gCO_2e/kg SO)	1,050.0	1,050.0	1393.9
$iluc_{SoyOil}$ - $iluc_{DGS}$		470.2	398.4

For more details of the calculations, please refer the linear ILUC model attached with the analysis. (LCA1_8-13)

Comment: The difference in Soy oil ILUC and DGS ILUC is consistent with Methods 1 and 2 even though Method 2 shows higher ILUC values for both DGS and soy oil. The results from method 2 are consistent with method 1 but do not rely on the ILUC of Method 1S.

The average difference in ILUC of soyoil and DGS is 434 g CO_2e/kg soy oil or 197 g CO_2e/lb soy oil. This should be added to the EF of the soy oil calculated from the soy oil for other uses. The sum should then be used to provide the substitution credit to the CO extracted. (LCA1_8-14)

Comment: Life Cycle Associates would like to take this opportunity to provide comments on the calculation of the carbon intensity (CI) ethanol production with DGS with corn oil co-products. Many ethanol plants produce distiller's corn oil (DOC) for use as animal feed or as a feedstock for corn oil biodiesel (COB) production. The pathways for the combination of corn ethanol and corn oil biodiesel require alignment to support a more equitable distribution of emissions between ethanol and biodiesel. For example, the current pathway does not include ILUC from corn and double counts the corn oil extraction energy for both the COB and corn ethanol pathways. An appropriate system boundary diagram for corn ethanol is shown in Figure 1. Here corn oil is either a feed co-product or an energy product for biodiesel feed. If it is a biodiesel feed, the emissions for the ethanol pathway should be allocated between the two products.

We are attaching a copy of my prior comments to this pathway for reference. However, the current CA_GREET model has a very significant inconsistency between the corn ethanol and COB pathways which lead to inaccurate accounting or carbon intensity of both corn ethanol (EtOH) and COB. We recommend making the following changes to the corn ethanol pathway.

- Provide substitution credit for corn oil used as animal feed based on soy bean oil\
    - Corn oil is a substitute for soy oil in animal feed and the same upstream and ILUC emissions should be the basis for the co-product credit.
- Allocate energy inputs and emissions between ethanol and corn oil used for biodiesel based on energy content of product
    - Both ethanol and corn oil for COB are energy products and the burden of the emissions should be distributed to both products based on energy.
- Allocate ILUC to ethanol and corn oil for COB based on energy content of products.
- Track carbon intensity in g/kg or g/lb of corn oil
    - Allows for GREET-type inputs for COB pathway

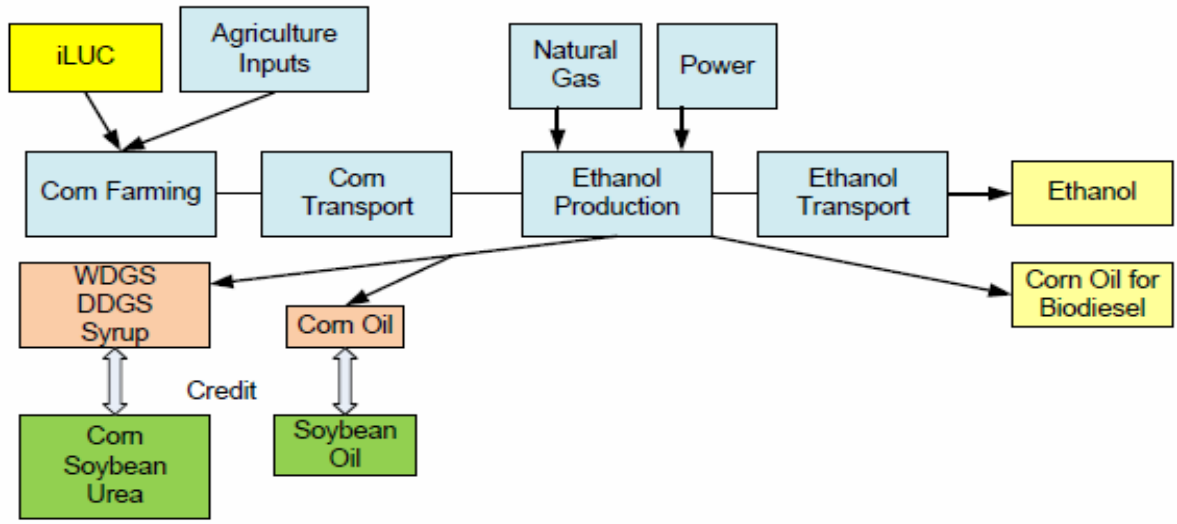

Figure 1. Corn Ethanol System Boundary Diagram

For the corn oil biodiesel pathway

- Update energy and emission allocation to corn oil. Provide a default value based on average of ethanol plants.
- Include ILUC for corn ethanol allocated to corn oil

The analysis here addresses only the indirect land use change associated with the corn ethanol pathway. Comments regarding ILUC for displaced soy oil are the subject of a subsequent comment.

The current corn ethanol pathway assigns all of the corn oil (CO) production as a part of DGS and gives credit based on the same displacement ratios as DGS. CO is used in animal feed as a direct substitute for soy oil and hence should be provided with a 1:1 displacement credit for soy oil. This implies that the amount of corn oil produced will no longer be included in the DGS amount, slightly reducing the DGS credit but increasing the amount of credit for CO.

Additionally, the corn oil used for BD production should be treated like an energy product. Therefore, similar to other pathways in CA_GREET, CO, as energy co-product, should be allocated all the energy inputs and the corresponding emissions based on the energy allocation method. Per the energy allocation method, the emissions are allocated to various products proportional to the total energy content of each of the respective co-product produced. This approach also implies that the corn oil does not receive a displacement credit. The CI of this CO is also associated with it and is carried over to the BD producer who essentially buys this CO along with its associated CI burden. ARB may choose to assign an average CI value for this to every COB producers for accounting simplicity.

To illustrate the proposed methodology, we calculated the CI for each scenarios using CA_GREET defaults and few assumptions. As per the default COB pathway, 0.03 gal of CO is produced per gal of ethanol. With a density of 7.6 lb/gal for CO, this results in 0.23 lb CO /gal EtOH. We also assumed the default EtOH yield, energy inputs, and chemical inputs for the corn ethanol pathway for calculation. The 3-CAMX region was selected in this example.

Table 1 below shows the CI calculation following the three different methods: the current method, soy displacement method for CO as feed, and energy allocation for CO as COB feedstock. It should be noted that the CI values are in terms of MJ of the fuel in the respective columns. Note that the corn oil in Table 1 is only the feedstock phase and subsequent processing to FAME is required for the BD pathway.

Table 1. Comparison of CI in g CO2e/MJ Fuel Calculation using Various Methods.

Parameter/Method	**Current**	**Soy Displacement**	***Energy Allocation***	
DGS lb/gal	5.64	5.41	5.41	
CO to feel lb/gal	0.00	0.23	0.00	
CO to BD lb/gal	0.00	0.00	0.23	
CI (g CO2e/MJ fuel)	Ethanol	Ethanol	Ethanol	Corn Oil
Feed	24.17	22.70	21.36	21.36
Fuel	31.97	31.97	30.08	30.08
T&D	3.90	3.90	3.90	3.90
Denaturant, g/MJ	0.69	0.75	0.91	0.00
ILUC	19.80	19.80	18.63	18.63
TTW	**80.54**	**79.12**	**74.87**	**73.97**

The table indicates a reduction in CI for ethanol using soy displacement method (79.12 g CO_2e/MJ) and an even greater reduction using the energy allocation method (73.97 g CO_2e/MJ) in comparison to the current method (80.52 CO_2e/MJ). By implication of energy allocation, the CO has a very similar CI as ethanol on per MJ of respective fuel basis.

The implication on the COB pathway analysis is also examined here. The inputs for the CA_GREET2.0 model are shown in Table 2. These values should be replaced with the allocated emission from the corn ethanol pathway.

Table 2. CA_GREET2.0. Default CO Extraction and DGS Debit.

511	**Corn Oil to Biodiesel (From DGS of a Dry Mill Corn Ethanol)**		
512	Corn oil yield, gal/gal EtOH	0.03	
513	Biodiesel yield, lb biodiesel/lb oil	1.10	
514			
515	**Corn Oil Extraction**		**CI, g/MJ**
516	Extraction energy, Btu/lb oil	924.29	**4.82**
554			
555	**Corn Ethanol DGS Debit**		**9.95**
556	DGS reduction due to Corn Oil extraction	4.30%	

As previously mentioned, the CI associated with the CO is carried forward along with it to the COB pathway where it adds the corresponding burden. These calculations are shown in the following Table 3. The TTW for ethanol and CO calculated above is first converted into g CO_2e/gal of EtOH. (the same result is achieved if total tons of emissions are tracked). For the CO, this value is then converted to emissions per lb of CO using the CO yield in lb/gal EtOH (256 g/gal ethanol/0.23 lb CO per gal EtOH). Subsequently, this value is converted to the g CO_2e/MJ of biodiesel using the CO to BD yield and BD LHV. These feedstock production emissions are equivalent to the current "Corn oil extraction" phase in COB (Table 2) but reflects the correct distribution of emissions. This approach also makes obsolete the DGS reduction debit phase as the corn oil upstream emissions reflect a share of the ethanol pathway.

Table 3. CI implications for Corn Oil Biodiesel Feedstock Phase

Method	**Current**	**Soy Displacement**	***Energy Allocation***	
CI\Fuel	Ethanol	Ethanol	Ethanol	Corn Oil
Emissions g CO_2e/gal of EtOH	5,827	5,724	5,417	256
Emissions g/lb CO				1,121
CO extraction in COB g/MJ BD	4.1			76.0
DGS reduction debit g/MJ BD	10.9			0
Total CO burden on COB g/MJ BD	15.0			76.0

In summary, this wet DGS pathway in CA_GREET2.0 is an improvement over the COB 007 pathway but it should be brought further in alignment of emission allocation. ARB should add LUC emissions for corn oil removed from DGS. Furthermore, the above approach is appropriate for all types of ethanol production including ethanol with front end corn oil extraction.

ARB should revise both the corn ethanol and the COB pathway in the new version of CA_GREET. (LCA1_8-15)

Comment: Corn oil credit calculation in the calculator continues to perpetuate the corn oil energy accounting issue. The LCFS attempts to assign carbon intensity according to a well-established life cycle analysis framework. Accurate distribution of the emissions between ethanol and corn oil helps maintains confidence in the system. Even though

the adjustments are small the allocation of emissions between ethanol and corn oil reflects a significant quantity of LCFS credits.

In our previous comments, we suggested multiple ways of rectifying the double counting of corn oil extraction energy. In this comment, we illustrate the implementation of one of the proposed solutions; allocating the total electricity used in the ethanol plant to both ethanol and corn oil produced based on energy content. This would produce a small amount of credit for the ethanol producers in terms of their ethanol CI and an equivalent amount of debit to be assigned to the biooil facilities using the corn oil as feedstock. The methodology maintains the system-wide consistency by creating an equal amount of credits and debits. Therefore, we provide the following table as an example of how ARB could calculate the average electricity used for corn ethanol plants to extract corn oil and to process ethanol.

	Existing Data					*Additional Calculation*			
Facility	**EtOH consumption**	**Corn Oil prod**	**Elec consumption**	**Elec use**	**CO yield**	**CO yield**	**EtOH**	**Elec credit**	**CO burden**
Unit	***gal/yr***	***lb/yr***	***kWh***	***kWh/gal***	***lb/gal***	***Btu/gal***	***Btu/gal***	***kWh/gal EtOH***	***kWh/lb CO***
1	66,557,036	19,146,449	38,547,255	0.58	0.29	4,601	76,330	0.03	0.11
2	76,754,542	15,508,102	48,432,009	0.63	0.20	3,231	76,330	0.03	0.13
3	90,290,644	14,876,638	46,463,833	0.51	0.16	2,635	76,330	0.02	0.10
4	92,129,485	0	53,471,005	0.58	0.00	0	76,330	0.00	0.00
5	89,641,321	16,788,530	62,932,666	0.70	0.19	2,995	76,330	0.03	0.14
6	54,812,964	10,287,224	40,051,057	0.73	0.19	3,002	76,330	0.03	0.15
7	90,360,856	21,887,695	48,284,297	0.53	0.24	3,874	76,330	0.03	0.11
8	72,112,930	16,538,538	55,606,689	0.77	0.23	3,668	76,330	0.04	0.15
9	53,541,132	9,098,748	39,592,231	0.74	0.17	2,718	76,330	0.03	0.15
10	99,080,283	20,422,393	56,933,420	0.57	0.21	3,296	76,330	0.02	0.12
Weighted Average/Total								**0.02**	**0.13**

We randomly generated data for 10 ethanol production plants in a realistic range of production values. Using only the information which is part of every LCFS pathway application, we calculate the yield of specifically corn oil in terms of Btu of corn oil produced per gal of ethanol produced. The only assumed factor in this calculation was the energy content of corn oil at 15993 Btu/lb (constant for all pathways). The EtOH energy yield is constant at 76,330 Btu/gal. The electricity consumed is then allocated between the EtOH and CO based on their energy proportions. The electricity allocated to the CO in kWh/gal represents the effective credit received by the ethanol pathway. The same value is then re-calculated in terms of kWh/lb of CO to be allocated to the CO produced, subsequently added to the CO to BioOil pathways.

	Balance Check	
Facility	Total EtOH credit	Total CO Burden
Unit	*kWh*	*kWh*
1	2,191,328	2,191,328
2	1,967,062	1,967,062
3	1,550,512	1,550,512
4	0	0
5	2,376,305	2,376,305
6	1,515,361	1,515,361
7	2,332,186	2,332,186
8	2,549,563	2,549,563
9	1,361,279	1,361,279
10	2,357,015	2,357,015
Total	**18,200,610**	**18,200,610**

As previously mentioned, we also checked for the balance between the total credits and debits generated using this methodology. As it can be seen in the following image, the total credits given to ethanol exactly match the burden added to the corn oil. Additionally, this method works perfectly system-wide even if some ethanol facilities do not produce any corn oil. Please refer to the attached excel file for more details on calculation.

The same procedure could also be part of the verification procedure for corn ethanol plants. We hope that this approach provides a transition to more accurate accounting of co-products from corn ethanol. (LCA3_117-1)

Comment: The treatment of corn oil under the LCFS remains an unresolved issue. Several facts come into play in creating this issue. First, ARB has been double-counting the energy for corn oil extraction and assigning emissions to the corn oil biodiesel pathway without subtracting the same from the ethanol pathways. Secondly, with the elimination of the 007 pathway with 4 g/MJ CI, the share of corn oil as biodiesel has dropped in California. This fact reflects the biodiesel industry's response to the market signals. Therefore, a continuation of the inaccurate carbon intensity signal is inappropriate and will lead to incorrect market outcomes.

Another factor to consider is that the source of corn oil for biodiesel plants may not be the same as ethanol plants providing ethanol to California. Our proposed solution of assigning the electricity for ethanol plants to corn oil is a conservative assumption. Ethanol plants outside the LCFSRT will likely have higher energy inputs and higher greenhouse gas emissions than those in the LCFS system. For example, many ethanol plants that produce wet DGS sell to California as they are better positioned to take advantage of the incentives under the LCFS. These plants will use less electricity than a typical ethanol plant.

Ultimately the source of data for energy assigned to corn oil is not that important as long as the credit assigned to ethanol and the debit assigned to corn oil is equal.

Consequently, we do not see any significant disconnect by assigning the average electricity to corn oil imported to California and allowing ethanol plants to use that value for allocation to corn oil. (LCA4_140-1)

Comment: And I urge you to consider many of the comments that I've considered, including, for example, re-examining the distribution of emissions between corn ethanol and corn oil. They both deserve a share of the ethanol plant emissions as well as the indirect land use. (LCA5_T38-1)

Comment: f. RFA continues to believe that all emissions associated with corn distillers oil (CDO) production (including an appropriate share of upstream corn production and land use change emissions) should be allocated to the CDO pathway, not the corn starch ethanol pathway. CI values for corn starch ethanol remain overly inflated due to the allocation of certain CDO-related emissions to corn starch ethanol. (RFA1_80-11)

Comment: No credit for corn oil offsetting soy oil (POET1_129-6)

Comment: The extraction energy and GHG emissions (2.91 g CO_2eq/MJ biodiesel or renewable diesel) that are being applied to corn oil is inappropriate and results in this energy being double-counted, first at ethanol plants and then for biodiesel/renewable diesel plants.

Ethanol plants are being asked for all of the electricity and natural gas consumption based on invoices. In the ethanol simplified calculator, there is no opportunity to subtract the portion of the energy that is derived from the corn oil extraction process.

The CI of corn ethanol is the sum of the emissions from all of the inputs less the emissions that are allocated to the co-products.

The corn oil is being assigned the same emissions as is provided by the DDG credit in the ethanol pathway. This is the proper alignment of the two system boundaries. By adding the corn oil extraction emissions to the corn oil biodiesel pathway, the system boundaries are distorted and the emissions are counted twice—once in the ethanol pathway and once in the biodiesel.

The corn oil pathway should not include the corn oil extraction emissions. (NBBCABA1_29-15)

> **Agency Response:** Allocation of energy use and emissions—including land use change (LUC) emissions—between ethanol and corn oil is an important issue and carries significant CI implications for ethanol and biodiesel/renewable diesel pathways. There are complicating factors in an allocation scheme described by the commenter, which include: the source of corn oil for biodiesel plants may not be the same as ethanol plants providing ethanol to California, corn oil may be purchased from aggregators and not from a specific ethanol plant making it difficult to disaggregate upstream emissions to corn oil. Moreover, extracting corn oil from DGS has ILUC implications because of its linkage with vegetable oil

and animal feed markets. For example, recognizing this linkage, EPA[49] recently accounted for displacement emissions when estimating the carbon intensity of the grain sorghum oil pathway. Extracting corn oil from DGS reduces the amount of DGS available to the animal feed market requiring additional animal feed supplements, which potentially result in an increase in emissions. At the same time, corn oil production may reduce the need to produce additional vegetable oils such as soybean oil resulting in GHG savings. Modeling such impacts is not a trivial arithmetic exercise and requires an econometric analysis of all direct and indirect effects using models such as the GTAP model. The simplistic approaches described above may not capture all the nuances of interactions among corn oil, animal feed and vegetable oil markets.

Disaggregation of electricity between ethanol and corn oil is not a straightforward computation. Electricity is primarily used for the starch ethanol production process with only a small requirement for extracting corn oil. It is, therefore, not technically accurate to assign emissions proportionally between corn oil and ethanol when most of the electricity use is for the ethanol production process.

Until an appropriate allocation framework is developed, staff believes that it is appropriate to continue to use the accounting method used in the CA-GREET2.0 model for corn oil CI assessment. Staff will revisit the allocation issue in a future rulemaking.

J-7.2. Multiple comments: *Corn Oil Credit Calculation*

Comment: 4. No credit for corn oil offsetting soy oil in biodiesel markets (POET1_129-4)

Comment: Before you go, Michael. We've heard some other people testify about the temporary CI value. You didn't mention it specific, but is there an –

…

Mr. Boccadoro: I did in my written comments and would concur with that. We did have about six specific written comments and that is one of those. (AECA2_T44-3)

Agency Response: Please see Responses D-4.1, D-4.2, D-4.3a, D-4.3b, D-4.5, D-6.4c, F-1.1, F-3.1, H-3, and J-10.3 in Chapter VI.

J-7.3. *Corn Oil Credit Calculation is Off*

Comment: Corn oil credit calculation is off for multiple reasons

[49] U.S. EPA 2018. Renewable Fuel Standard Program: Grain Sorghum Oil Pathway, Final Rule, 40 CFR Part 80 [EPA-HQ-OAR-2017-0655; FRL-OAR] Available: https://www.gpo.gov/fdsys/pkg/FR-2018-08-02/pdf/2018-16246.pdf

- The EF of soy oil (cells D55:58 on EF tables) are incorrect. We calculated the correct EF in attached greet in BioOil sheet for your reference (including the N2O from fert and CO2 from urea). The total soy oil CI should be the sum of the 4 blue cells next to soy farming calculations (near row 320). This can be verified by the intermediate feedstock calculation in cell G358 (both should match, except correct the GWP formula in the row 358 first). We further checked this through making a biodiel disagg for GR3 which matched this number. The calculations for this is also described in a later section in this analysis.
- The credit calculation formulas on EtOH sheet (in cells E89:90) essentially make the credit independent of the corn oil lb/gal by first multiplying AP58 in cell E90 and then dividing the same in the cell E88. In the attached version, we have fixed the calculation in cell E88 to rectify it.
- The ILUC of soy oil also needs to be incorporated in the credit. This is described in a later section of this analysis. (LCA1_8-5)

Agency Response: The comment related to emission factor errors is based on a draft version of the Simplified Calculator provided during the informal rulemaking process. These errors do not exist in the version included in the formal rulemaking process.

For comments on indirect land use change (ILUC), please see Responses J-7.1 and J-7.4 in this chapter.

J-7.4. *Soy Oil Production*

Comment: CO credit in verification calculator is based on substation of soy oil. The EF for the soy oil should be based on the Soy oil LCI from Soy Oil for other uses on the BioOil sheet. The GWP of carbon black and organic carbon as well as the short term GWP should be made equal to 0. The equation determining this EF is as follows.

$$E_{SO,\ other} = E_{SB} / \rho_{SB} / OYF \times X_{SO} + (E_{SO,\ Extract} \times OYF + E_{SO,T\&D})$$

where,

$E_{SO,\ other}$ = GHG of soy oil (soybean farming + SO extraction) for other uses such as for CO substitution credit. (g CO_{2e}/lb soy oil)

E_{SB} = GREET upstream fuel cycle for soybeans per bushel = (E_{Farm} + $E_{Fert/Chem}$ + $E_{T\&D}$)

ρ_{SB} = Density of soybean on dry basis (lb soybean/bu soybean) = 52.2

OYF = Oil yield factor (lb soyoil/lb soybean) = 0.2

X_{SO} = Allocation factor for soybean to soyoil = 0.2

$E_{SO,\ Extract}$ = Unallocated soy oil extraction energy and emissions

$E_{SO,T\&D}$ = Soy oil transportation and distribution energy and emissions per lb soy oil.

(LCA1_8-9)

Agency Response: The commenter is referencing a version of the model and Calculator posted during the informal rulemaking process. The model and Calculator released during the formal rulemaking process do not include a substitution credit for corn oil. The LCFS life cycle analysis currently does not account for potential contributions from black carbon or organic carbon.

J-8. Multiple Comments: *Biogenic Volatile Organic Compound Emissions*

Comment: The GWP for the non-combustion (fugitive) emissions during the fuel production phase should be zero as they have biogenic origin. The change needs to be made in the CA_GREET3 as well as the starch sheet. (LCA1_8-2)

Comment: The GWP for the non-combustion (fugitive) emissions during the fuel production phase should be zero as they have biogenic origin. The change needs to be made in the CA_GREET3 as well as the starch sheet. (LCA1_8-7)

Comment: In our previous letters, we highlighted the erroneous inclusion of biogenic VOC emissions during ethanol production and T&D phase as fully oxidized GHG emissions. In the earlier versions of CA_GREET, the fugitive VOC emissions were included as fully oxidized GHG emissions and added to the corn ethanol WTT carbon intensity. Non-combustions VOC emissions at the production plant as well as during the T&D phase were included in the CI. This adds an unjustified, systematic burden on the carbon-neutral corn ethanol pathway as the carbon source of the VOC is biogenic and should be considered carbon neutral in terms of carbon intensity calculation.

In the current CA_GREET version, ARB has already corrected the error associated to the T&D phase by subtracting the biogenic VOC emissions in the GHG calculation cell. Please refer to the cell J434 in the EtOH sheet of CA_GREET2.0 tier 1 model. The VOC emissions are first added to the cell J429 as a part of criteria pollutant calculation. But then are subtracted in the cell J434 to calculate the GHG emissions associated to the T&D phase.

The model also appropriately calculates the loss factor based on these fugitive VOC emissions in the cells DG338 and DH338 for the production phase. However, the non-combustion VOC emissions generated during the production phase are still erroneously added to the GHG emissions during production phase. The VOC emissions added to the cell I429 (from M377) are converted to fully oxidized GHG emissions in the cell I434 without any accounting for their biogenic nature.

There are multiple methods of correcting this error. The simplest and most straight forward way of rectifying this is to apply the same treatment to this VOC as the fugitive VOC in the T&D phase. The amount of non-combustion VOCs (M377) should be subtracted from the cell I429 before the application of the carbon content factors from

the Fuel_Specs sheet. This effectively makes the GWP of the biogenic VOC to be zero without creating any error in the loss factor calculation or other pathway phases.

Correcting for this reduces the pathway CI by about 0.007 g/MJ which may seem like a small number. But it should be noted that this is a systematic error which affects each and every certified corn ethanol pathway and every gallon of corn ethanol sold in California. Over the total volume of corn ethanol sold in California, such a small change in CI generates an impact. It is also critical from a consistency perspective to treat the emissions from all biogenic sources equally. (LCA1_8-16)

> **Agency Response:** Except for tailpipe emission factors and a few other California-specific factors, the CA-GREET3.0 model and Simplified CI Calculators are primarily based on the GREET_1 2016 version of Argonne's life cycle analysis model. Argonne's GREET_1 2016 model does not include biogenic Volatile Organic Compound (VOC) and CO emissions in the accounting of GHGs in the life cycle analysis of transportation fuels. However, non-combustion VOC emissions in the corn or sorghum ethanol production process are not biogenic, since they include evaporative emissions from fossil fuels, and these emissions are included in the life cycle accounting of fuels. Non-combustion VOC emissions in the T&D phase (from bulk terminal and refueling station) are however, treated as biogenic in the CA-GREET3.0 model in line with Argonne's version of the GREET model.

J-9. *Fuel Pathway Classifications and Application Process*

J-9.1. *Requesting Credit Generation for Design-Based Pathways*

Comment: The second suggestion would be for newly built production facilities or additional bolt on production is to allow firms that are building these facilities to apply for a "Design-based Pathway (§95488.9 (e)) that can be utilized in lieu of a temporary pathway from Table 8. This approach would encourage innovative technologies to be deployed in traditional designs that could further reduce GHG footprints of the production facilities. (WE1_78-5)

> **Agency Response:** Staff's primary intent in proposing to include 'design-based' pathways is to allow CARB to signal the investment community to help identify new low-CI fuel production technologies with the greatest potential for commercial-scale production of ultra-low carbon fuels. If the applicant is careful in their submission, design-based pathway CIs are likely to be indicative of the CIs the project will receive once built, but because there can be differences in performance between engineering design and final commercial operation, design-based pathways cannot be used to generate credits.
>
> All pathway types that can be used for generating credit need to reflect a conservative estimate of the carbon intensity of actual commercial production of the fuel. The regulation includes provisions to develop new temporary pathway

CIs which could alleviate concerns related to potential loss of credits for fuel sold in the California market before a provisional pathway can be certified.

J-9.2. Multiple Comments: *Include other Renewable Natural Gas Pathways in the Tier 1 Classification*

Comment: We have been working closely with ARB staff and do not find those efforts reflected in the proposed regulations. This is especially true for Specific Comment 2 below. Staff have already developed and shared a draft simplified calculator for the wastewater sector to review, however the draft regulation shows wastewater sector projects assigned to the Tier 2 pathway classification, which precludes the use of a calculator. Since staff has already developed and provided the draft calculator, we request the wastewater sector be listed under Tier 1 classification. (CASA1_94-1)

Comment:

2. Section 95488.1(d) – Defines fuel pathways that fall under Tier 2 classification, and sub (2) includes: Biomethane from sources other than landfill gas. Furthermore, it states that the Tier 2 classification shall apply to fuel pathways that the Board's staff has limited experience evaluating and certifying. However, staff has worked diligently to develop specific pathways for mesophilic digestion of sewage sludge at wastewater treatment plants, and recently shared a draft simplified calculator which they intend to introduce during a 15-day amendment once this rule is finalized. Biomethane sources other than landfill gas should certainly be eligible for a Tier 1 pathway, which has been the intent of the Air Resources Board. Please provide clarity on how the wastewater sector can fruitfully participate in the LCFS program as intended in the Short-Lived Climate Pollutant Reduction Strategy.

3. Section 95488.7 – Specifies the requirements to apply for a Tier 2 classification, which include a full GREET 3.0 calculation and a comprehensive Life Cycle Analysis. These requirements are costly and will discourage participation in the program. This is especially true given the efforts of and dialogue we have already had with staff to eliminate this requirement through the development of a simplified calculator. Listing the wastewater sector under Tier 1 classification will mitigate this issue. Please provide confirmation of this. (CASA1_94-4)

Comment: 4. Biomethane from all sources should be included in Tier 1 pathways.

…

4. Biomethane from all sources should be included in Tier 1 pathways.

BAC agrees with the concerns raised by the California Association of Sanitation Agencies about the classification of biomethane from sources other than landfill gas as Tier 2, which subjects most instate biomethane to much more onerous requirements. As CASA notes in its comments:

Section 95488.1(d) – Defines fuel pathways which must fall under Tier 2 classification and sub (2) includes: Biomethane from sources other than landfill gas. Furthermore it states that the Tier 2 pathway classification shall apply to fuel pathways that the Board's staff has limited experience evaluating and certifying. Staff worked diligently to develop specific pathways for mesophilic digestion of sewage sludge at wastewater treatment plants and have now developed a simplified calculator which they intend to introduce during a 15 day amendment once this rule is finalized. Biomethane sources other than landfill gas should certainly be allowed as Tier 1 pathways and this seems the intent of the Air Board. Please provide clarity on how the wastewater sector can fruitfully participate in the LCFS program.

Biomethane from sources other than landfill gas is critical to reduce Short-Lived Climate Pollutants and should not, therefore, be subjected to greater requirements and costs than other low carbon fuels. (BAC1_99-6)

Comment: Reduce barriers to encourage adoption of renewable natural gas. We encourage actions that will encourage rapid adoption of renewable natural gas, including establishing lookup table or Tier 1 CI's for known dairy bio-methane pathways and reducing administrative requirements in the early years to encourage market participation and increase liquidity in the LCFS credit market.

…

2. Reduce barriers to encourage adoption of renewable natural gas

In *§95482, Fuels Subject to Regulation* fossil compressed natural gas (fossil-CNG) is removed as an opt-in fuel, and in the mid-2020s, fossil-CNG becomes a deficit-generating fuel. We anticipate renewable natural gas (RNG) supplies to increase in order to substitute for fossil-CNG, and encourage CARB to encourage adoption of this fuel through the LCFS program. Since state programs[6] are driving ambitious reductions of greenhouse gas emissions, we encourage CARB to establish a lookup table or Tier 1 CI for dairy digester biomethane sources from known fuel pathways. This will encourage natural gas suppliers in the state to opt-in to the LCFS program, generate credits and increase market liquidity.

[6] The 2017 Climate Change Scoping Plan update: https://www.CARB.ca.gov/cc/scopingplan/2030sp_pp_final.pdf
2017 Short-lived Climate Pollutant Reduction Strategy: https://www.CARB.ca.gov/cc/shortlived/meetings/03142017/final_slcp_report.pdf

(PGE1_120-5)

Agency Response: To address stakeholder comments staff developed Tier 1 Simplified CI Calculators for biomethane from Anaerobic Digestion of Wastewater Sludge, Food, Green & Other Waste, and Dairy and Swine Manure. The use of these Calculators is expected to expedite review, validation and certification of Tier 1 pathways for these fuels. Staff expects that the inclusion of a Tier 1 framework for these three fuels will alleviate the stakeholder concerns expressed in the above comments. Pathways which cannot be accurately calculated under the Tier 1 frameworks will be able to pursue a Tier 2 approach, but staff expects

most biomethane pathways to fit within the Tier 1 framework. The Dairy and food/green/other organic waste calculators will provide additional support for CARB's efforts related to Short Lived Climate Pollutants.

J-9.3. *Tier 1 Wastewater Biomethane Calculator*

Comment: In addition, we ask that the wastewater sector be assigned to tier 1 pathway classification. We've been working really closely with the Air Resources Board staff on the development of a simplified calculator which was supposed to be -- or will be introduced in the 15-day comment period that was mentioned in the presentation.

However, the wastewater sector has now been assigned to the tier 2 classification in the draft changes, which would preclude the use of the calculator that's already been developed. So we do ask that the wastewater sector to be moved to tier 1. (CASA2_T9-1)

> **Agency Response:** Staff has addressed this comment by developing the Tier 1 biomethane from wastewater calculator. For facilities which cannot model their pathways using the Tier 1 Calculator, a Tier 2 option is available subject to the substantiality requirements listed in 95488.9(a). Please see also Response J-9.2 in this chapter. .

J-9.4. Multiple Comments: *Tier 2 Pathway Application Process for Electricity Pathways*

Comment: 3. The Tier 2 Pathway application process for electric distribution utilities and retail sellers of electric energy (i.e. load serving entities) needs to be better defined and clarified; and

…

<u>The Tier 2 Pathway application process for load-serving entities need to be better defined and clarified.</u>

As noted in San Francisco's comments on the LCFS workshop (submitted December 4, 2017), an individual load-serving entity should be able to establish its own specific carbon intensity for electricity used as a transportation fuel using the Tier 2 Pathway approach. While electricity usage is listed as an eligible Tier 2 Pathway, the corresponding requirements do not clearly identify the requirements that a load-serving entity must meet in order to establish its specific carbon intensity profile. Allowing load serving entities to establish their own specific carbon intensities would further improve the accuracy of the LCFS calculations as well as recognize load serving entities that provide their customers with tariffed electric service with a carbon intensity significantly lower than the California average.[6]

[6] To limit the number of applications, CARB may want to impose a threshold that the carbon intensity must be X% lower than the California average.

The proposed regulation states that CARB staff has limited experience in evaluating and certifying Electricity pathways not found in the Lookup Table (Section 95488.1(d)). This statement overlooks CARB's extensive experience in determining the CI of electric energy provided as input to LCFS fuel production. Based on this experience it should not be difficult for CARB to certify the GHG intensity of a load-serving entity seeking to document a CI lower than the California Average Grid Electricity Pathway.

The approach needed to determine an individual load-serving entity's carbon intensity is similar to the current approach used by CARB to determine system-wide California grid emissions, which CARB staff proposed to update every year. Almost all of the already-filed Tier 2 Pathway applications, for example, utilize the CA GREET 3.0 model. This model already determines the carbon intensity of electricity used in fuel production on a regional basis.

Under the CA GREET 3.0 model, although electricity can, and does, move throughout the entire interconnected Western United States electric grid, the CA GREET 3.0 model allocates this electricity, and calculates a separate carbon intensity for each of the 26 sub-regions identified by the EPA for the Western United States.[7] Allowing an individual LSE to calculate its own carbon intensity would be a relatively easy next step in further refining the CA GREET 3.0 methodology and would improve the accuracy of the LCFS calculations. The LCFS regulations already provide detailed granularity for the inputs used to determine a fuel's carbon intensity,[8] and there is no reason a similar disaggregation should not be allowed for the electricity used as a transportation fuel.

[7] "Staff restructured the available GREET1 2016 regional electricity resource mixes to allow fuel producers to use more representative sub-regional electricity resource mix to obtain a more representative CI for the sub-region." (CA-GREET 3.0 Supplemental Document and Tables of Changes, p. 20)

[8] For example, the LCFS regulations list a separate carbon intensity for 165 different California oil fields and 372 oil fields world-wide (including California). LCFS Proposed Regulations Table 9.

The CA GREET 3.0 model (which relies extensively on the EPA's E-GRID model) determines the carbon intensity for each region by determining the relative share of each generating resource (e.g., hydro-electric, natural gas, coal) used to serve electric load and then proportionately applying a GHG emissions factor for each source.[9] This approach is comparable to the "book and claim" methodology proposed to determine the LCFS eligibility of renewable electricity used to reduce the carbon intensity of electricity supplied as a transportation fuel (Section 95488.8(i)).

[9] This GHG intensity includes any life-cycle GHG emissions associated with the electric generation such as GHG-emissions from mining (in the case of coal) or fuel processing (in the case of nuclear power).

Given that the above methodologies should already be sufficient to determine the GHG-intensity of electric energy provided under all Tier 2 Pathway applications, as well as Lookup Table Pathway applications using 100% renewable electricity, there is no reason a similar methodology could not be used for determining the GHG intensity of an individual load-serving entity EDU or retail seller as part of a Tier 2 Pathway application.

The electric industry is already highly regulated, so there are a number of pre-existing data sources (many of which are required to be submitted to various government agencies) that CARB could rely on to verify an individual load-serving entity's CI.[10]

[10] This includes CARB's own Mandatory Reporting Requirements for GHG emissions for electric generating sources, WREGIS, which tracks renewable generation throughout the Western United States; the CEC's Power Source Disclosure Report, which tracks procurement by resource type for retail sellers; and RPS compliance reports filed with the CEC and CPUC.

Accordingly, CARB should create a separate Tier 2 Pathway application process specifically for load-serving entities based on its pre-existing, and already used, methodologies for determining the carbon intensity of the electric sector. (CCSF1_87-3)

Comment: Clarification of Tier 2 Pathway application process for Electricity provided as a transportation fuel

Rather than try to shoehorn a Tier 2 Pathway application for electric energy into the current Tier 2 application requirements, which are geared towards liquid fuel, we are proposing separate language for a Tier 2 electricity-based application. The proposed language largely parallels existing language in the proposed regulation regarding determining CI values for the electric system and the use of "Book and Claim" accounting to determine the relative share of each generating resource used by a load-serving entity to meet its energy needs.

…

PROPOSED NEW SECTION 95488.7(b) TO ADDRESS

TIER 2 ELECTRICITY PATHWAY APPLICATIONS

§ 95488.7 (b)

(1) Use of LSE Specific Electricity Pathway. In order to reflect that certain LSEs have a portfolio of electricity generating resources in California with a carbon intensity significantly lower than the California Average Grid Electricity Pathway, a LSE may submit a Tier 2 Pathway to reduce the CI of electricity supplied as a transportation fuel on an annual basis. The LSE shall use the methodology described in the supporting document specified in section 95488.5(e), adjusted to reflect the LSE's specific portfolio of electricity generating resources to determine the CI of the LSE.

(2) Book-and-Claim Accounting for Low-CI Electricity Supplied as a Transportation Fuel or Used to Produce Hydrogen. A LSE may use indirect accounting mechanisms, without regard to physical traceability, for determining the portfolio of electricity generating resources used as an input to the CA-GREET 3.0 model to determine the reduction of the CI of electricity supplied as a transportation fuel or for hydrogen production through electrolysis, provided that;

(A) The electricity must be supplied to the grid within a California Balancing Authority (or local balancing authority for hydrogen produced outside of California);
(B) Electricity is generated using equipment owned by, or under contract to the LSE.
(C) The LSE provides contract invoices and metering data necessary to support its calculations; and
(D) The electricity portfolio may span only two quarters. If the electricity quantity (and all associated environmental attributes, including a beneficial CI) is supplied to the grid in one calendar quarter, the quantity claimed for LCFS reporting must be matched to the grid electricity dispensed for transportation fuel to electric vehicles, fixed guideway systems or for hydrogen production no later than the end of the following calendar quarter.

(3) Applicability of Other Tier 2 Requirements: For any Tier 2 Pathway application seeking to use only electricity as a transportation fuel, the Executive Director may waive any Tier 2 application requirements that are inapplicable to the use of electricity as a transportation fuel.

(CCSF1_90-4)

Agency Response: The rule would permit Tier 2 fuel pathway applications for LSE-specific electricity used as a transportation fuel. Staff believes that the framework in the proposed regulation order, especially contained in the Tier 2 requirements section (95488.7) and the Indirect Accounting for Electricity and Biomethane section (95488.8(i)) provide sufficient guidance regarding the requirements for such pathway applications. If a large quantity of such pathway applications are submitted under the proposed rulemaking, staff is open to considering drafting additional regulatory guidance regarding fuel pathway applications for Tier 2 LSE-specific electricity if necessary.

J-9.5. ***Margin of Safety***

J-9.5a. **Comment:** REG requests clarification for the conservative margin of safety concept. Upon first glance, it appeared that was the max CI number in the case of over generation to be used. For example, if our plant had a 36 CI and a conservative CI of 38 for an average of 37, we would just need to stay under the 38 CI. Upon second glance, it looks like the average CI is the max CI. Going back to our example, we would have to stay under the 37 CI instead of the 38 CI. (REG1_88-22)

Agency Response: If an entity elects to add a margin of safety to the operational CI, the maximum CI (with the margin of safety included) must not be exceeded. In the example provided in REG1_88-22, the operational CI for REG's fuel pathway would be required to stay below a CI of 38, inclusive of the margin of safety.

J-9.5b. **Comment:** Section 95488.4 of the LCFS amendments suggests that fuel pathway applicants should add a conservative "margin of safety" to increase the certified CI above any potential operating CI. The margin of safety is implied to protect against variability in operations to diminish the risk of non-compliance with the certified CI. This concept of a "margin of safety" is counterintuitive to the concept of real lifecycle fuel pathway emissions reporting. The LCFS utilizes the sophisticated GREET model to accurately model the well-to-wheels emissions for fuels delivered to California. CI modeling through GREET with an added layer of assurance through a mandated verification program should therefore preclude the need for a "margin of safety". (CE1_92-8)

> **Agency Response:** Producers who anticipate increase in pathway CI due to potential for changes in pathway inputs (i.e., energy use, fuel or co-product yield, increase in transport distance for feedstock) used during initial validation should consider the option to add a margin of safety to their CI calculated using the CA-GREET3.0 model. This will ensure compliance if the pathway's actual reported CI, as evaluated during verification, exceeds the originally certified CI. Adding a margin of safety is optional for fuel pathway applicants.

J-9.6. ***Lookup Table Pathways***

J-9.6a. **Comment:** Under section 95488.5(b) *Lookup Table Pathway Application Requirements*, entities seeking approval for solar or wind electricity, time-of-use, and all hydrogen Lookup Table pathways "must submit the fuel pathway applicant attestation letter pursuant to the requirements of 95488.8(a)" and additional documentations. The language is not clear whether that applicant must submit the attestation letter **only** or must go through the entire pathway application requirements, including third-party validation. Under section 95500(a)(1)(A), fuel pathway applicants, as specified in sections 95488.5 through 95488.8 are applicable for third-party validation. According to ARB's Staff's Initial Statement of Reasons (ISOR),

> "The requirement to submit an attestation letter ensures that the fuel pathway applicant will exercise due diligence when they select the Lookup Table pathway which closely corresponds to their actual fuel pathway. In proposing this solution staff intends to balance the desire to maintain a simple and streamlined application process with adequate assurance of accuracy in GHG reduction claims."

The "desire to maintain a simple and streamlined application process" appears that Staff's intention was for applicants to submit the attestation letter and supporting documents only, and not require applicants to go through third-party validation. Additionally, in the ISOR, ARB's Staff stated that "verification of temporary CIs or lookup table CIs would not be required," however, did not state the same regarding third-party validation for lookup table CIs. LADWP recommends that ARB clarifies in the Final Statement of Reasons (FSOR) that applicants are only required to submit the attestation letter and supporting documents. (LADWP1_38-10)

Agency Response: Entities seeking to report fuel transactions using the Lookup Table pathways listed in 95488.1(b)(2), including EV charging from zero-CI sources, smart charging pathways and all hydrogen pathways, must register in the AFP and submit an attestation letter pursuant to the requirements of 95488.8(a). Submission of all supporting documentation required in 95488.5(b) is required. Third-party validation is not required for Lookup Table pathways.

J-9.6b. Comment: The current Low Carbon Fuel Standard ("LCFS") program derives the carbon intensity ("CI") of grid electricity from the ninth edition of the U.S. EPA's Emissions and Generation Resource Integrated Database ("eGRID"), which is incorporated into the California-modified Greenhouse gases, Regulated Emissions, and Energy use in Transportation ("CA-GREET") model. As such, the CI for California electricity is based on the 2010 average California generation resource mix.

The California generation resource mix has changed significantly since 2010. According to electricity data from the California Energy Commission's Quarterly Fuel and Energy Report ("QFER"), renewable energy resources represented 25.5% of the Total System Electric Generation in 2016, nearly double the proportion of renewable energy in 2010 (13.9%). Similarly, coal represented 7.7% of the state's generation in 2010 compared to 4.1% in 2016. The increased reliance on renewable energy and decline of coal generation have reduced the carbon intensity of the state's generation resource mix since 2010.

The Joint POUs support maintaining the CI of average grid electricity in a lookup table, and the proposed 93.42 gCO2e/MJ for 2019.[6] Furthermore, the Joint POUs appreciate and support the proposal to annually update the Lookup Table pathway for California average grid electricity used to calculate credits for EV charging. In so doing, the LCFS program will more accurately account for the GHG emissions reductions associated with EV charging from grid electricity that is increasingly generated from renewable energy resources.

[6] Table 7-1 in § 95488.5(3).

(JPOUS1_59-3b)

Agency Response: The commenter is mistaken about the baseline year (2010) for the Lookup Table CI of California average grid electricity. A 2010 baseline is used for the calculation of CIs only for the baseline fuels (i.e., gasoline and diesel). For the current amendments, the CI for California Grid Average Electricity used as a transportation fuel used the QFER 2016 generation mix published by the California Energy Commission. This CI will be updated annually to reflect annual updates in QFER data and staff appreciates commenters support for this provision. The annual update is expected to reflect increasing contribution from renewables in California's electricity mix.

J-9.7. ***Temporary Pathway Applications***

J-9.7a. **Comment:** However, we request the following additional clarifications on the temporary pathway application process:

- What is the application process and method of submission to CARB staff? What data is required?
- Will CA-GREET 3.0 modelling be required for temporary pathway applications?
- Will an approved temporary pathway be posted on the CARB website and made available to any applicant meeting same process requirements, or will it be exclusive to the company or facility that applied? (ECOENGINEERS1_B5-10)

Agency Response: Fuel reporting entities must submit a temporary pathway request form in the AFP. Although detailed process data will not be required, information related to sourcing of feedstock (including limited invoices), production of fuel (and transport to California, if applicable) will be required from the applicant. Upon review, staff may request additional information to verify existence of facility and transportation logistics to ship fuel to California. The fuel reporting entity must also attest that the temporary fuel pathway requested best represents the actual feedstock-fuel combination. In 2019, all temporary pathways approved shall be posted on the LCFS certified CI website and include applicant information. Approved temporary pathways will be identified as connected to each facility to facilitate tracking of quantities reported in the program.

J-9.7b. **Comment:** It is difficult to imagine every possible processing scenario that producers may look to implement and make pathway applications for. We ask that ARB look at providing flexibility to use engineering judgments and technically sound assumptions and calculations in lieu of absolute measurement for every process input. An example would be the language at 95488.6(a)(2)(D) which would require installation of automated metering equipment for a fuel production facility that is co-located. Installation of fully automated metering equipment may not be practical and could be expensive. Another approach would be to allow calculation of usage based on equipment information (motor horsepower ratings, etc.), especially in situations where the electricity usage is not a significant contributor to the overall CI value. We have not identified every section of the regulation where there might be opportunity to provide additional flexibility but believe that ARB staff would be familiar with the areas where these opportunities might present themselves. We want to ensure that the regulations provide some flexibility and ask for reasonable alternatives to some of the prescriptive requirements where the alternative would provide a sound technical approach. (P661_55-8)

Agency Response: To ensure accurate accounting of GHG emissions to a fuel pathway, requirements for dedicated metering equipment is a requirement in the regulatory amendments. Given the potential for actual process energy use to be significantly different from modeled (or rated) energy use and the likely variability

in energy use attributable to temporal variation in process parameters, dedicated metering is required for facilities which have co-located processes.

J-9.7c. Comment: *NextGen Urges CARB to Improve Transparency Relating to Details of Method 2 Pathway Applications*

CARB publishes all Method 2 pathway applications for fuels seeking to generate LCFS credits, however, in most cases the critical quantitative information is redacted as confidential business information (CBI). We understand that CARB has an obligation to protect the CBI of pathway applicants, however this protection removes so much data that it is functionally impossible for independent researchers to verify claims made by applicants. The extensive redaction also reduces the value of Method 2 pathway applications to researchers and limits the evolution of research in this space.

We urge CARB to improve the transparency of Method 2 applications where possible. We ask Staff to review current protocols related to redacting CBI to determine whether more transparency is possible without improperly exposing CBI. Even if there are no legally feasible changes to the treatment of any particular pathway, we ask CARB to explore whether aggregated average quantitative data from similar pathways could be released. This would protect the CBI of any particular company, but provide a better lens for researchers to see real-world behavior of advanced clean fuel production systems, which will accelerate relevant research into this space and help better calibrate models against real data. (NEXTGEN1_124-53)

> **Agency Response:** In response to similar requests from other stakeholders, staff is committed to improving transparency of information included for public comments. Staff will develop guidelines for Tier 2 applicants to ensure adequate information is included in the public postings to facilitate constructive feedback yet preserve confidentiality of process data deemed as such by the applicant.

J-9.8. *Provisional Pathways*

Comment: Section 95488.9(c)(3) discusses adjusting CI and credit balance for provisional pathways and (c)(3)(A) and (B) address actions that will be taken by the Executive Officer based on whether the verified operational Cis are higher or lower than the provisional CI. Will the +/- 5% or 2 CI variance that is proposed for verification be applied here to determine whether adjustments should be made? It seems reasonable that the verified operational CI would only be considered higher or lower if it was outside these established tolerances. (P661_55-7)

> **Agency Response:** Provisional pathway operational CIs must remain under the certified CI (cap) to comply with the LCFS regulation and thereby avoid credit adjustments, consistent with non-provisional pathways. No CI variance is proposed for verification. The verifier's material misstatement assessment is not related to potential variability of operational CI over time. Instead, the verifier's process for assessing the risk of material misstatement of the calculated operational CI concerns sampling past data to check for calculation errors that

may exceed 5 percent. For more information about the verifier's assessment of material misstatement, please refer to ISOR pages III-152 and 153.

J-9.9. *Solar Steam as a Renewable Process Energy Input*

Comment: The use of renewable energy in the production of liquid fuels can reduce their CI, contributing to lower costs and more certain compliance with the program. We believe that the broadest use of renewable energy in liquid fuel production is beneficial to the program. This is of course true for biofuels as well as petroleum fuels.

Solar steam as a renewable process energy input for biofuel facilities can potentially result in lower CIs, for ethanols as well as other fuels. GlassPoint is concerned that Section 95488.8(h) as drafted excludes solar steam as a potential input, and would like to see this updated. (GLASSPOINT1_65-12)

> **Agency Response:** In response to this comment, staff modified the proposed regulation to explicitly include solar steam. Please refer to section 95488.8(h)(3) for the relevant text.

J-9.10. *Renewable Energy by Biofuel Producers*

J-9.10a. Comment: We also request that CARB consider eliminating another obstacle to cost-effective deployment of renewable energy by biofuel producers. Wind electricity, solar steam, and solar electricity production varies annually and is weather dependent. As a result, fuel production operations which use renewable power and steam will likely use varying amounts of total annual fossil energy inputs to back up those variable renewable inputs. For petroleum production using the Innovative Crude mechanism, the program is self-adjusting for this annual variation, as the number of LCFS credits generated is directly proportional to the amount of steam and power produced with renewable resources. This isn't the case with biofuel facility pathway certifications. Biofuel plants are assumed to have a fixed set of inputs such that a fixed CI value can always be delivered.

GlassPoint recommends the LCFS program address this issue for biofuel facility pathways. With the variation of solar and wind, there needs to be a way to certify a pathway without being ultra-conservative in the expected renewable energy fraction and CI score. (GLASSPOINT1_65-14)

> **Agency Response:** In a future rulemaking staff is interested in pursuing ex-post crediting based on the actual reported performance of biofuel facilities, rather than crediting based on ex-ante pathway CI values. However, initiating a change of this magnitude would affect numerous stakeholders, and staff was not able to address this issue in the current rulemaking. In addition, fuel pathway CIs are based on two years of data, which staff believes will at least partially mitigate the variability of CI resulting from intermittent renewable process energy inputs.

J-9.10b. Comment: Under the currently proposed rules, in any given reporting cycle, in a year of higher wind or solar output resulting in a CI lower than the facility's pathway,

there is no benefit to the producer. But on the other side, in a year of lower solar or wind output, if an entity is slightly over their certified CI score there are enforcement implications. Staff's recommendation for facilities to avoid any possibility of not achieving their CI score is to build in "head room". The "head room" approach doesn't work here, as the amount of potential annual variation (up to 30% depending on location and technology) requires such conservatism as to prevent investments in renewable technology. GlassPoint recommends that this matter be addressed so that biofuel producers can make cost-effective investments in renewable energy for their production facilities. (GLASSPOINT1_65-15)

> **Agency response:** As pointed out by the commenter, the fuel pathway applicant may choose to add a conservative margin of safety, of a magnitude determined by the applicant, to request a certified CI value higher than the operational CI, to account for potential variability of process inputs and minimize the risk of non-compliance with the certified CI. Staff understands that there could be seasonal variability related to process inputs like feedstock or renewable energy sources and, therefore, requires calculating CI based on 24 months of operational data that would average out seasonal variability allowing the pathway applicant to choose an optimum average CI value. The framework to maintain the operational CI below the certified value allows credits to be issued on a quarterly basis prior to annual third-party verification without resulting in a significant credit adjustment in case the verified operational CI is found by CARB to be higher than the certified value. This provides pathway applicants with the flexibility to monetize their credits sooner, minimizing potential credit invalidation and resulting impacts in the credit market.
>
> Staff believes an alternate option to avoid the need to have a margin of safety in a certified CI value would be to issue the credits based on a verified CI value following a third-party check. This would ensure the credits are generated based on accurate verified data and credit balances are not subject to retroactive adjustments.

J-9.11. Multiple Comments: *Appealable Decisions*

Comment: CARB has proposed that the following decisions by the Executive Officer are not appealable: classification of a fuel pathway, scientific defensibility demonstration for Tier 2 pathway applications, substantiality requirements for multiple pathways for the same feedstock-fuel combination or Tier 1 pathways using innovative methods, and use of temporary fuel pathways. Fuel pathway applicants would have no recourse to provide additional data to support an applicant's position prior to the Executive Officer making a permanent final decision. Furthermore, the Executive Officer is not obligated to notify the applicant in writing of the results of the evaluation process. We find this position to arbitrary and capricious and unsupportable by Administrative Law. CARB cannot circumvent due process in an effort to minimize administrative burdens, or provide the Executive Officer with absolute authority over scientifically-supported discourse in favor of political expediency. We contend this provision should be removed from the proposal. (DGD1_69a-4).

Comment: CARB has proposed that the following decisions by the Executive Officer are not appealable: classification of a fuel pathway, scientific defensibility demonstration for Tier 2 pathway applications, substantiality requirements for multiple pathways for the same feedstock-fuel combination or Tier 1 pathways using innovative methods, and use of temporary fuel pathways. Fuel pathway applicants would have no recourse to provide additional data to support an applicant's position prior to the Executive Officer making a permanent final decision. Furthermore, the Executive Officer is not obligated to notify the applicant in writing of the results of the evaluation process. CARB cannot circumvent due process in an effort to minimize administrative burdens, or provide the Executive Officer with absolute authority over scientifically-supported discourse in favor of political expediency. We contend this provision should be removed from the proposal. (VALERO1_69b-7).

> **Agency Response:** The commenter suggests that due process requires some form of appeal from specified decisions that the EO must make in reviewing pathway applications and requests to use temporary pathways. In CARB staff's view, the critical considerations here are fairness and efficiency. With multiple informational interface opportunities for pathway applicants throughout the process, it is not feasible to have a formal appeal process for each decision made along the way toward pathway approval. Pathway applicants submit a significant amount of information to CARB for review, and for each of hundreds of applications, there are dozens of steps and decisions along the way. To date the iterative process by which applicants have worked with staff on those steps has worked well, balancing the needs of the market for timely decisions and availability of resources. In the iterative process, applicants can contact CARB staff to check whether all necessary information has been received, and staff can contact an applicant to resolve questions or to request missing information. Adding an appeal step would slow the processes even more, while draining valuable CARB staff time. Moreover, all applicants remain guaranteed due process protection of their interests by state and federal law. California law provides for administrative appeals of agency decisions to the Office of Administrative Hearings or to Superior Court. Both avenues provide an opportunity for a dissatisfied applicant to be heard by a neutral judge.

J-10. *Temporary Pathway Carbon Intensities*

J-10.1. Multiple Comments: *Temporary Pathway Carbon Intensities are Arbitrary or Punitive*

Comment: It seems premature and unnecessary to eliminate previously adopted pathways and assign them higher carbon intensity values that appear arbitrary. We highly recommend retaining the original pathways and carbon intensity values until alternatives are developed. (CASA1_94-2)

Comment: In § 95488.9(b), temporary CI's have been increased by an additional 5% above the most recent, most conservative pathway certified with that feedstock. WSPA requests that a rationale for adding an additional 5% to the most conservative fuel

pathway certified with that feedstock-fuel combination be provided as the additional 5% appears to be overly punitive. (WSPA2_61-22)

Agency Response: Temporary pathways are intended to be conservative representations of feedstock-fuel combinations in the LCFS, for use in special circumstances. Staff used the most conservative pathway currently certified with each feedstock-fuel combination, added five percent, and rounded to the nearest five, in order to provide reasonable assurance that the temporary pathway CI would not be lower than a potential future certified CI with this feedstock-fuel combination. This methodology has been applied to each temporary pathway, where feasible, with the exception of biomethane from dairy manure andbiomethane from organic waste and LNG/L-CNG pathways (please see Response J-10.3, Revise Temporary Pathway CIs for Biomethane, in this chapter, for the rationale for these temporary CIs). Credit generation due to use of a temporary pathway as proposed is not expected to be overly burdensome, especially with the addition of Simplified CI Calculators for Tier 1 pathways (available for most biomethane pathways).

J-10.2. *Temporary Pathway Scores for Transportation Fuel Production*

Comment: California is projected to have a population growth rate of nearly 14% by 2030 from a 2015 baseline (an annual growth rate of just under 1%)[1]. As the population continues to grow, demand for energy, specifically transportation energy will grow. It can be surmised that new facilities for transportation fuel production will need to come online. Since these newly built facilities either inside or outside the state of California will not have production data required to produce a CI score; they will be required by rulemaking to utilize Table 8. In both cases technology for these Tier 1 fuels as well as their feedstock have been well known and widely implemented for decades, it is overly harsh to prescribe such high temporary pathway scores and could deter new production facilities to come online to meet California demand. We are suggesting two options that could remedy these potential pitfalls. The first is to re-establish Table 7 as the baseline temporary CI score for fuels with indeterminate CI's and create a secondary table that would represent regions of production used to increase the CI scores for import/transportation distance. This approach would be a more accurate representation of GHG accounting set forth by CA-GREET.

[1] Hans Johnson- Public Policy Institute of California, California's Future Population (http://www.ppic.org/content/pubs/report/R_116HJ3R.pdf)

(WE1_78-4)

Agency Response: Staff disagrees with commenter on the need to bifurcate the Table of Temporary CIs in the regulation. Temporary pathway CIs are intended to be conservative representations of feedstock-fuel combinations in the LCFS available for fuel production facilities that do not yet have commercial production data to qualify for a certified fuel carbon intensity. Adding an additional table with modifiers for specific feedstock sourcing and fuel production regions would create additional burden on staff to develop CI scores for potentially hundreds of region-transport combinations. This would delay review

and certification of fuel pathways for all applicant. Given the availability of a provisional pathway option requiring only a minimum of three months of commercial production data, it is expected that applications will be certified in no more than two full quarters once an application is submitted. Therefore, staff will maintain the streamlined methodology currently suggested in the proposed regulation.

J-10.3. Multiple Comments: *Revise Temporary Pathway CIs for Biomethane*

Comment: In 95488.9 (b)(4), CARB is proposing an amended list of temporary pathways for fuels with indeterminate CIs. The pathway for dairy or food/green waste is awarded a temporary CI of 0, which does not adequately represent the greenhouse gas benefits associated with dairy RNG projects. DTEBE understands that the purpose of the temporary fuel pathways is to allow producers to sell at an extremely conservative CI unless they are willing to undertake the process to certify a project specific pathway. However, a temporary pathway of 0 for dairy RNG projects downplays the significant carbon benefit provided by dairy projects. Dairy RNG projects obtain a strong CI in the LCFS program because of their beneficial use of otherwise released methane and their destruction of other harmful climate pollutants. Even a conservative CI should better reflect the negative carbon benefits of these projects. A more accurate temporary pathway will help provide dairy RNG producers safety if any problems arise during the registration period or if they are facing the expiration on claims for their environmental attributes on stored RNG. DTEBE suggests that CARB consider developing a unique temporary pathway for dairy RNG that more accurately reflects the negative carbon value of dairy RNG projects rather than grouping these projects with food waste and assigning a non-representative CI. DTEBE is happy to work with CARB and other stakeholders in the RNG industry to provide quantitative analysis and production data to develop a unique temporary CI for dairy RNG projects that is more reflective of the significant climate benefits these projects bring about. (DTEBE1_56-7)

Comment: Through Section 95488.9 (b) CARB provides an important Temporary Pathways mechanism. According to Table 8 “Temporary Pathways for Fuels with Indeterminate CIs” the value for dairy is proposed at zero (0).

We would strongly encourage CARB to review and adjust this value, since it doesn't take into account the methane destruction from a dairy project. A temporary CI may prove an important mechanism if a project specific pathway is delayed. We would recommend a value of -150, which is a conservative number reflecting the CIs for dairy digester projects determined to date. (AECA1_72-9)

Comment: Clean Energy appreciates the addition of a temporary fuel pathway (TFPC) for digester projects (0 g/MJ for Dairies/Green waste and 35 g/MJ for Wastewater) however, the likely delta between the actual CI for one of these projects and the TFPC will be significant, especially for a dairy digester. For example, the most recent dairy application had a CI of -254 g/MJ which translates to an additional 0.25 credits per MMBtu of production relative to the 0 g/MJ TFPC. At current market pricing this can yield millions of dollars of lost revenue and LCFS value to the buffer account in just the

first quarter of operation. A TFPC of 0 g/MJ may be appropriate for wastewater treatment and organic diversion digester projects but is overly conservative for dairy projects that have been proven to achieve CI scores as low as -254 g/MJ or more. Clean Energy recommends that Staff create a separate TFPC for dairy projects at -150 g/MJ, which is still conservative relative to anticipated dairy project CI scores but will allow producers to recognize appropriate value while their true CI application is under evaluation. A more accurate temporary pathway will provide dairy RNG producers more safety as they work to optimize facility operations during the start-up and registration periods, and provide a pathway for additional dairy RNG producers to develop and build their projects. (CE1_92-10)

Comment: I would like to offer a couple concerns we have with what's being proposed. And I'd like to start off first with the CI for dairy digester pathways.

The temporary field pathway is listed at zero grams per megajoule, which we do believe is too conservative. Staff has already approved and certified a dairy digester pathway with a CI score of negative 254. And we do believe the delta between the temporary CI of zero and a typical dairy CI of negative 254 represents a significant loss of monetary value to a dairy producer looking to cover exceedingly high up-front capital costs.

At the current market pricing, this would yield millions of dollars in lost revenue and LCFS value to the buffer account in just the first quarter of operation. So we do ask that consideration be given to a temporary fuel pathway for dairy digesters to be in a more appropriate range of maybe 100 to -- negative 100 to negative 150 so producers can recognize appropriate value while the true CI application is under consideration. (CE3_T31-2)

Comment: 3. The Temporary Fuel Pathways for dairy, diverted organic waste and wastewater biogas are unnecessarily conservative.

…

3. The Temporary Fuel Pathways for dairy, diverted organic waste and wastewater biogas are unnecessarily conservative.

BAC agrees with the comments of Clean Energy that the proposed Temporary Fuel Pathways for dairy and wastewater biogas are unnecessarily conservative and will make it harder to finance new projects. Given the urgency of constructing new dairy digesters and expanding capacity at wastewater facilities to convert diverted organic waste to energy, we urge the Air Board to adopt Temporary Fuel Pathways that are closer to the carbon intensity levels that have been certified for recent projects in these sectors. For instance, dairy biomethane has been certified at negative 276, but the Temporary Fuel Pathway would assign it a temporary carbon intensity of zero. There is no basis for adopting Temporary Fuel Pathways with so much higher carbon intensity values. This will cause much higher levels of uncertainty for projects and, especially, for project financing.

BAC recommends that Temporary Fuel Pathways be no more than ten percent higher carbon intensity than the average of projects in the same sector that have been certified by the Air Resources Board. (BAC1_99-5)

Comment: Change Diary Biomethane Temporary Fuel Pathway Look Up Value to -100

In Table 8 of Section 95488.9(b), ARB defines the Temporary Fuel Pathway for Biomethane CNG and Biomethane LNG from feedstock Dairy as 0. AMP recommends that ARB staff set a temporary CI score of -100 to accurately account for dairy biomethane baseline. ARB's new proposal pegs the temporary (look up values) to the worst performing fuel pathway. AMP's facility is the only dairy project currently in the program. Prospective CIs of other dairy projects are also negative. Therefore, AMP is recommending ARB adjust the lookup value specifically for biomethane derived from dairy projects to accurately reflect data that is publicly available. (AMP1_86-5)

Comment: This lost value associated with the delta between operational and certified CIs becomes a problem for entities reporting transactions under a temporary fuel pathway. The draft amendments for NGV temporary fuel pathways, for example, are extremely conservative and are in no way indicative of actual biogas or fossil NGV fuel delivered in California. In fact, the temporary pathway CI values appear completely arbitrary and without consideration of the current or future RNG mix in California. Credit generators who are forced to generate credits under these pathways will lose significant value and revenue associated with the delta between the actual operating CI and these nonsensical abnormally high temporary fuel pathway CIs. Biogas digester pathways will be affected most by this provision considering ARB has eliminated the lookup pathway value for biogas derived from a high solid anaerobic digestion process. This means that any digester project that does not have its own pathway will have to generate LCFS credits on at least one of the temporary biogas to NGV pathways while their actual pathway is under review. This will represent a significant amount of lost revenue considering digester pathways achieve significantly negative carbon intensities (as low as -300 g/MJ or more). (SCG1_75-10)

Comment: Table 8 – Temporary Pathways for Fuels with Indeterminate Carbon Intensities. This table provides a temporary carbon intensity value of 40 g CO_2e/MJ for CNG derived from wastewater sludge biogas. Based upon the Initial Statement of Reasons (ISOR), it appears this was calculated based on the previous pathway for small treatment plants of 30.5. The ISOR states that it added 5% to this value and then rounded upward to the nearest multiple of 5 value. This would result in a value of 35 as opposed to 40. Please clarify. Likewise, LNG and C-LNG from wastewater biogas are assigned CI's of 55 and 60, respectively, but with no explanation for their derivation. Please provide it. (CASA1_94-7)

Comment: The other issue is we have serious concerns about the temporary fuel pathways. They are extremely conservative and will make it very hard to finance projects for diverted organic waste and dairies. (BAC2_T4-3)

Comment: But you are concerned about the CI intensity, such as the waste water treatment generators of RNG, and the dairies. The default temporary CI is zero for anaerobic digestion. And we've been doing carbon-negative fuel for years.

And the pathway submitted takes about two to three years in order to get a pathway, in order to get carbon negative. We're doing some right now on the verge of certification about 100 to 200. And to be carbon negative, minus 25 for default and now go to zero would really hurt an emerging industry.

We'd like to do a Tier 1 simplified CI calculator. And I think that staff is very familiar with anaerobic digestion. Because right now, if we don't get that, it's going to be somewhat of a buzz kill for a lot of developments I'm working on.

Once again, we're in-state, making in-state RNG. We're community scale, and we feel that we can take the heavy-duty diesel fleet off of diesel now with RNG fuel with a near NOx engine in disadvantaged communities. It's a near-term solution for short-lived climate pollutants.

We're losing momentum by having a CI go to zero as a temporary a CI. And plus, with intensity going to 7.5 instead of 10, once again the demand for RNG is at a loss. So we have an emerging industry. We're ready to get organic waste out of the landfill. We're ready to be zero waste. And this hiccup on CI for zero is setback. So please reconsider allowing us to remain carbon negative. (CCC1_T52-3)

> **Agency Response:** Please see Response J-10.1, Temporary Pathway Carbon Intensities are Arbitrary or Punitive, in this chapter for an overview of the methodology used to assign most temporary pathway CIs. Staff does not propose to use the methodology suggested in BAC1_99-5, as it does not ensure that temporary pathway CIs will be conservative, which would undermine the intent of this provision.
>
> The Temporary CI for the wastewater biomethane pathway is 45 g/MJ, a value which used the CI for a single Tier 2 wastewater biomethane pathway CI certified in March 2018 (43.02 g/MJ) and applying the same methodology used for all temporary pathway CIs. With limited information about the likelihood of CIs for such projects, staff chose to utilize the most conservative temporary CI. With a Tier 1 Simplified CI Calculator being available for wastewater biogas pathways, a conservative Temporary CI is not expected to be a burden on such applicants. LNG and L-CNG temporary pathway CIs for other biomethane pathways add 15 g/MJ and 20 g/MJ, respectively, to the Temporary CI for CNG from this source of biomethane. These are based on differences in CI for LNG and L-CNG pathways compared to the baseline CI of the corresponding CNG pathway. Temporary CIs for LNG and L-CNG for biomethane from wastewater sources accordingly are 60 g/MJ and 65 g/MJ for LNG and L-CNG, respectively.
>
> Staff reevaluated the temporary CI for dairy biomethane. To date, there is only one certified pathway for dairy biomethane, with a CI of -254. To take into

account the methane avoided credit, staff has determined that a value of -150 g/MJ is a sufficiently conservative temporary CI which still reflects a large emissions reductions and credit generating potential associated with this fuel. Staff has updated the temporary CI value for dairy biomethane to -150 g/MJ.

Staff also reevaluated the temporary CI for biomethane from food, green or other waste. Using the life cycle approach in the Simplified CI Calculator for Biomethane from Anaerobic Digestion of Food, Green and Other Organic Waste (June 20, 2018), staff has determined that assigning a temporary CI of zero could underestimate GHG emissions from this fuel in some cases. Accordingly, staff has moved to assign Temporary CIs for biomethane to CNG/LNG/L-CNG from these sources to align with that of Temporary CIs for anaerobic digestion of wastewater sludge.

Regarding the concern in comment CCC1_T52-3 with reducing the program targets for 2020, see Response F-3.1 in this chapter.

J-10.4. *Temporary Carbon Intensity Score for Fossil Natural Gas*

Comment: Over the last three years the LCFS program has utilized three versions of the GREET model. Each iteration of the model has made sweeping changes in assumptions that have drastically impacted the CI values of the majority of fuels in the LCFS program. Under the GREET 1.8b model, fossil CNG had a carbon intensity of 67.7 g/MJ and achieved 30% GHG reduction relative to conventional diesel. The CI for fossil CNG has increased in each model from 79.46 g/MJ under GREET 2.0 and now up to 86.57 g/MJ under GREET 3.0. This represents nearly a 30% increase in just three years. CI's for other fossil fuels have not increased at all over this time and in fact the conventional diesel CI has decreased slightly under the GREET 3.0 model. Such large increases in the fossil CNG CI are puzzling especially considering there has not been a corresponding increase in the gasoline or diesel CIs which are also fossil fuels with similar upstream production emissions. The natural gas industry will conduct a thorough analysis to validate this CI but cannot do so until the full unaltered version of the GREET 3.0 model is released. Any changes in to CI values should not be placed into a draft rule until stakeholders are given a proper amount of time to review and verify all associated calculations and assumptions.

ARB has listed the temporary fossil LNG and LCNG values at 100 g/MJ each, a seemingly arbitrary value that is poses an immediate, unnecessary and unfair challenge to the natural gas industry. Although it is unlikely that these pathways will ever be used, ARB must understand the implications of publishing these unrealistic abnormally high CIs. While some might argue that these are only temporary fuel pathways, unrealistic values effectively communicate to the fuel market that fossil LNG and LCNG emit 10% more GHG emissions (EER adjusted LNG and LCNG) than conventional diesel which is absolutely both false and misleading. The NGV industry experts have worked tirelessly across California to convert heavy duty diesel trucks to run on clean burning LNG. ARB's decision to arbitrarily inflate CI values only undermines these efforts by indicating that fossil LNG and LCNG have a CI of 100 g/MJ regardless if these are temporary. In

fact, we have seen advocates use similar data in the past as a representative number of NGV technology to show other transportation strategies to be better when it is not the case. These We therefore strongly believe that these values must be revised in the final draft to accurately reflect the current CI of fossil LNG and LCNG in the market. (SCG1_75-13)

> **Agency Response:** The assertion that the Lookup Table pathway for North American Natural Gas has increased by 30 percent over the past few versions of CA-GREET is incorrect, as the CA-GREET3.0 value cited (86.57 g/MJ) is from a previous draft CI published during a workshop which has since been significantly revised downward. Increases in the CI of fossil natural gas has primarily been driven by updates to methane leakage rates. The timeframe provided for public comment periods and review of stakeholder comments is in compliance with the Administrative Procedure Act (APA) requirements. For fossil LNG, the highest CI certified and published CI in the pathway website is 91.03 g/MJ and supports the value of 95 g/MJ for temporary fossil LNG pathways. Given the difference between LNG and L-CNG pathway CIs are around 3 g/MJ, a temporary (conservative) pathway CI of 100 g/MJ is justifiable when considering a temporary fossil LNG pathway CI of 95 g/MJ.

J-10.5. Multiple Comments: *Revise Temporary Pathway Carbon Intensities for Starch Ethanol and Biomass Based Diesel*

Comment: CARB staff has proposed a revision to the "Temporary Pathways for Fuels with Indeterminate Cis" (Table 8 formerly Table 7) that seem almost punitive and arbitrary in nature. Two examples of which are for corn based ethanol and biomass-based diesel from plant oils (excluding palm oil). These pathway scores now are listed as 90 gCO2e/MJ and 65 gCO2e/MJ. Both of these traditional renewable fuels have been the cornerstone of the LCFS and have been previously listed as scores of 75.97 gCO2e/MJ and 56.95 gCO2e/MJ. The increases from the former Table 7 and newly proposed Table 8 which replaces it in rulemaking represent and 18.5% increase in corn ethanol CI and 14.1% increase in the biomass-based diesel from plant oils (excluding palm oil). Current registered and approved FPCs for Corn Ethanol (Tier 1) do not exceed 85.58 gCO2e/MJ. (WE1_78-3)

Comment: RPMG requests the temporary CI for corn starch ethanol remain at 75.97 g/MJ. The proposed regulations also introduce an overly conservative temporary fuel pathway code (TFPC) for corn starch ethanol. Despite the average carbon intensity of ethanol experiencing historical reductions, the proposed TFPC CI *increased* from a CI of 75.97 to 90 g/MJ. The 2018 Illustrative Compliance Scenario lists an average CI of 71 for corn starch ethanol. The market further establishes the average CI of fuel sold in California through economics, which provides an available baseline for determining a representative TFPC. However, the proposed TFPC was determined by staff using the most conservative pathway certified, arbitrarily increasing it by five percent and then

rounding it up to the nearest five CI points. That methodology is ultra conservative and it should be changed.[3]

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(RPMG1_64-10)

Agency Response: Please see Response J-10.1 in this chapter for an overview of the methodology used to develop Temporary pathway CIs. Staff used this methodology for assessing the temporary fuel pathway for corn starch ethanol. The highest currently certified pathway for corn ethanol is 85.72. Using the methodology suggested, the temporary CI assigned to corn starch ethanol is 90 g/MJ. Likewise, the highest certified pathway for biomass based diesel is 61.94. Using the same methodology, the temporary CI assigned to biomass-based diesel from plant oils feedstocks is 65 g/MJ.

J-10.6. *Combining Temporary Carbon Intensities for Biodiesel and Renewable Diesel*

Comment: Kern disagrees with ARB's approach to combine temporary CIs for biodiesel and renewable diesel into a single CI for biomass-based diesel, and urges ARB to revert to previous provisions with temporary CIs specific to each fuel. Kern acknowledges ARB's attempt to simplify the temporary pathways listed in Table 8. However, Staff's conservative approach results in a penalty in excess of 5 grams CO2e/MJ to renewable diesel producers needing to utilize the temporary pathway code provision. This is a significant detriment to the fuel producer for what are negligible regulatory simplifications – literally the elimination of one temporary pathway entry from a list previously containing only two diesel substitutes. Kern requests ARB revert to the previous provision consisting of separate temporary pathways for biodiesel and renewable diesel, and ensure the new temporary CI for renewable diesel is adjusted only in the manner described in the Initial Statement of Reasons (ISOR), without the impact of biodiesel's temporary CI. (KERN1_115-6)

Agency Response: For all of the certified CIs for biodiesel and renewable diesel through 2017 being similar for the same feedstock, staff elected to use a single FPC for biodiesel and renewable diesel attributable to a given feedstock. Temporary CIs are not intended to capture applicant-specific emission reductions in greenhouse gas emissions but, rather, serve as a conservative estimate of such reductions. The purpose of FPCs in Table 8 is to ensure credits (albeit conservative) accrue to the fuel supplier during a period when a minimum of three months of production data is as yet unavailable after initiation of commercial fuel production or significant energy and yield improvements have been implemented in the production facility. Staff, therefore, will not be differentiating Temporary CIs by feedstock for biodiesel and renewable diesel in Table 8.

J-10.7. *Include Temporary Fuel Pathway Codes for Renewable Propane*

Comment: Table 8 of the proposed LCFS regulation order should include temporary fuel pathways codes for renewable propane that are the same as those for renewable diesel. (WPGA1_121-7)

> **Agency Response:** The regulation includes a provision to add new Temporary CIs to account for low carbon fuels produced using feedstock/technology combinations not available in Table 8. Staff is committed to adding renewable propane if supplies of this fuel are available for use in the California transportation fuels market.

J-10.8. *Use of Temporary Pathways*

Comment: Section 95488.9(b)(2) – States that temporary pathways may only be used to earn LCFS credit in the quarter in which the application is approved and one additional quarter. Re-application is allowed, but another full submittal is required. This is an onerous process if another alternative has yet to be developed and will create market uncertainty. We recommend allowing credit to be earned, once approved, until an alternate pathway is developed. (CASA1_94-6)

> **Agency Response:** The process of requesting an extension for use of a temporary pathway is relatively straight forward. Temporary pathways are intended for short-term use, and thus are approved in two-quarter increments. Automatically approving temporary fuel pathways in perpetuity might dis-incent the applicant submitting a regular pathway application and would undermine the temporary nature of this classification.

J-10.9. *California Grid Mix Electric Vehicle Pathways*

Comment: Fuel pathway holders must be able to recognize the full value of emissions reductions associated with delivery of fuel to California. ARB plans to update the California grid mix EV pathway every year following the release of grid mix data from the California Energy Commission which will allow EV pathways to take full advantage of recognizing the actual emissions of their fuel with zero lost value for their assigned values with no invalidation risk. (SCG1_75-11)

> **Agency Response:** CI values of all fuels are intended to be representative of long-term steady state operation, and all applicants can eliminate invalidation risk by selecting an appropriately conservative CI. Staff intends to balance the desire to maintain a simple and streamlined application process with adequate assurance of accuracy in GHG reduction claims. Evidence shows that the electricity grid in California is getting cleaner every year, while staff is aware of no such reductions in the fossil NG system. However, an updated Lookup Table value for North American Natural Gas has been provided, allowing a fossil CNG applicant to generate LCFS credits without invalidation risk. If an annually-updated source of data for California NG becomes available hereafter,

staff may consider more frequent updates to the North American Natural Gas Lookup Table CI in a future rulemaking.

Please refer to Responses J-10.1, J-10.2, and J-10.3 in this chapter for an overview of the rationale and the methodology used to assign temporary pathway CIs. Please refer to section 95488.5(d) in the regulation for updates to electricity pathways. Please refer to Response in T-1 of this chapter for a discussion on fuel neutrality between EV and NGV.

J-11. Multiple Comments: *Substantiality Requirements*

Comment: ACE members are strongly opposed to the proposed substantiality requirement outlined in §95488.9(a) to limit applicants from submitting pathways with differences in CI. Limiting pathway applications in this way violates the spirit of the LCFS and would discourage innovation and process improvements. We believe it should be removed from the final regulation.

CARB suggests it wants to limit applicants from submitting multiple pathways with minimal differences in pathway CIs and to limit fuels that could be certified under the Tier 1 framework from requesting consideration under the Tier 2 framework. The provision requires a minimum CI reduction as a prerequisite to apply for a new pathway. We are very concerned this will prevent incremental reductions from being recognized and monetized to foster additional modifications or improvements. While a 1 gram reduction in CI may not seem consequential at face value, under CARB's proposal, a plant producing 50 million gallons of low carbon ethanol which reduces their CI from 70 grams to 69 grams would be prohibited from submitting the reduction for pathway approval. With credit prices fetching approximately $140 per metric ton of CO_2, a 1 gram reduction is worth more than 1 cent per gallon of ethanol. In the example of the 50 million gallon per year ethanol plant which reduced its CI from 70 grams to 69 grams, the 1 gram reduction could generate a return of up to $565,000. There is real value in continuing to encourage and reward even 1 gram reductions in CI. Incremental process improvements built on top of one another generate additional profits and enable reinvestment to achieve further CI reductions. CARB should strike the substantiality requirement from the final regulation to promote and support the continuation of these incremental reductions. (ACE1_41-5)

Comment: RPMG recommends the proposed regulations be reviewed and revised to encourage the continued production of low CI fuels. Limitations within the proposed simplified calculator, substantiality requirements, and overly conservative defaults need to be addressed. **Specifically, RPMG requests the following revisions: Remove new pathway application substantiality requirements and establish Simplified CI Calculator default values that are reflective of real world industry practice.**

The LCFS program is promulgated to encourage the production of cleaner low-carbon fuels to be used for transportation in California. This design structure is meant to promote innovation in the renewable fuel production process which results in a lower carbon intensity fuel. The proposed LCFS regulations require producers to provide

significant amounts of verified data at their own expense. Meanwhile technical elements of the proposal severely limit recognition of innovation and do not allow for claiming incremental GHG reductions. (RPMG1_64-7)

Comment: The substantiality requirement outlined in § 95488.9(a) must be removed completely. This provision is unclear in its scope, and can be interpreted to require a significant minimum CI reduction as a prerequisite to apply for any new pathway and therefore is a barrier for producers seeking recognition of their carbon reductions. The proposed provision is a strong signal to the market and investors that the program is not interested in maximizing carbon reductions from all fuel sources. According to the ISOR, the substantiality requirement is designed to limit applicants from submitting multiple pathways with minimal differences in pathway CIs and to limit fuels that could be certified under the Tier 1 framework from requesting consideration under the Tier 2 framework. It is RPMG's position that all producer emission reductions that can be demonstrated and verified be considered for new pathway applications, including Tier 2 modification for Tier 1 eligible pathways. Recognition of all sources of carbon reductions is to the programs benefit. Further, all reported pathway quantities will be dually reconciled between reporting parties by mandated quarterly reconciliation procedures as well as mandated independent verification engagements for fuel producers and importers. The confidence level of accuracy for this reported data should be significantly high. This provision must be removed from the proposed regulations for the program to continue to encourage the production of cleaner low-carbon fuels.

This proposed regulation is contrary to the LCFS' stated goal to encourage the production of cleaner low-carbon fuels. It is the incrementally small process changes that build on top of one another and the immediate additional funds for reinvestment that allowed the ethanol industry to achieve the historical CI reductions it has contributed to the LCFS program thus far. Unfortunately, ethanol producers are unable to fully capture these reductions due to benchmarks used in the market. The substantiality requirement will prevent incremental reductions from being recognized and monetized to further foster additional modifications for further reductions. The substantiality requirement must be removed to promote and support the continuation of these incremental reductions. Through discussion with Staff, RPMG believes that additional clarification of the proposed language to narrow the scope may help to alleviate concerns with sub-section (a)(1)(A). We look forward to continuing the dialogue on this front. (RPMG1_64-8)

Comment: a. While we appreciate the intent of the proposed substantiality requirements (i.e., to reduce CARB staff workload related to processing pathway applications), RFA believes the proposed requirements will discourage innovation and improvement under the LCFS. The LCFS was designed in such a way that low-carbon fuel producers can potentially be rewarded for any meaningful reduction in CI, even if those reductions may at first appear to be small. This is how the program has encouraged investment and innovation. We believe the proposed substantiality threshold of a 5% reduction versus the reference pathway is too large and will result in the marketplace forgoing low-cost, near-term CI reduction opportunities at existing facilities. For example, an ethanol producer that could achieve a 2.5-3 g/MJ reduction

in its CI value versus the reference pathway likely would be prevented from applying for a new pathway because of the level of the proposed substantiality threshold. At current LCFS credit prices, this producer would be forgoing 3-4 cents per gallon in additional CI premium value, reducing the incentive to invest in further improvements and efficiencies.[3]

[3] Assumes CI value of 50-60 g/MJ (without ILUC penalty) and LCFS credit value of $150.

b. We encourage CARB to revise the substantiality requirement to 1 g/MJ for *all* proposed pathway applicants, not just those with source-to-tank CI values of 20 g/MJ or less. (RFA1_80-14)

> **Agency Response:** The proposed substantiality limits are a continuation from the threshold established under CA-GREET2.0. The limits of 5 percent for CIs greater than 20.0 g/MJ and 1.0 g/MJ for pathway CIs lower than 20 g/MJ were instituted to limit applicants from requesting multiple pathways with minimal differences in pathway CIs and to limit requests for a Tier 2 pathway even for incremental reductions in CI relative to a Tier 1 pathway.
>
> However, to address stakeholder concerns related to potential loss of LCFS credit value attributable to limitations imposed by the substantiality requirements, staff has modified the substantiality requirement language to clarify the intent and scope of this provision. First, staff has clarified that the substantiality requirements do not apply when a fuel pathway holder is re-applying with a new operational data period or is replacing an existing certified CI pursuant to 95488.10(a)(6). Staff has also modified the text such that the substantiality requirements apply to multiple <u>applications</u> for the same feedstock-fuel combination, rather than multiple <u>pathways</u>. Lastly, staff has clarified that the substantiality requirements do not apply to applicants seeking Tier 2 pathways due to the use of low-CI process energy sources or use of carbon capture and sequestration. Staff believes these modifications will address the stakeholder concerns expressed in the above comments.

J-12. *Co-Processing*

J-12.1. Multiple Comments: *Co-Processing Considerations*

Comment: We understand CARB's desire to facilitate the near-term ability of obligated parties to generate LCFS credits. However, due to the immense scale of refining operations and their astonishing level of complexity, we believe more time is needed to study this subject before carbon intensity pathways are issued. Specifically, we recommend that CARB restart its Co-processing Workgroup to help ensure pathways are promulgated in a manner that is 100% accurate for each refinery project and carried out in a manner fully consistent with the long-term goals of the LCFS program. <u>We further believe that no pathways should be approved until the Co-processing Workgroup has reviewed key issues and developed a set of recommendations.</u>

We suggest the following areas for further consideration by CARB and/or the Co-processing Workgroup:

- Lifecycle models. CARB suggests that "Evaluating co-processing pathways using a Tier 2 framework is consistent with the goal of streamlining the pathway application and certification process."[11] At this point in time, we disagree that this is an appropriate approach because models for each respective refinery technology do not exist—they still need to be developed by CARB. And since the Tier 2 framework is usually masked in redacted statements, that process alone will not afford the level of public review necessary to provide confidence to stakeholders that carbon intensity values are accurate.

  [11] https://www.arb.ca.gov/regact/2018/lcfs18/isor.pdf, page III-72.

- Public information. Refineries should be required to provide the same level of operational detail that has been made available by and for other industries. If co-processing is allowed to generate LCFS credits, the technology must go through a public process that provides sufficient information for the public to validate the accuracy of carbon intensity pathways. In addition, data marked as "confidential business information" submitted on Tier 2 applications should be reviewed by CARB legal staff to ensure it meets the criteria set forth under California law.
- Verification of renewable content. It is believed that a very small fraction of renewable feedstock inputs become renewable diesel fuel through co-processing. Therefore, it is critical that renewable content in finished fuel be measured via C14 radiocarbon dating rather than a mass-balance approach, which would overestimate renewable content. ASTM test method D6866 has been approved for this analysis.
- Limitation on co-processing. If co-processing is allowed under the LCFS, boundaries for this type of credit generation should be considered. We recommend the Refinery Investment Credit Pilot Program (RICPP) as a sensible model. Under RICPP, projects are of limited duration, refiners are not allowed to generate more than 20% of their obligation through the program, and credits cannot be traded. Given the incredible complexity and scope of refinery operations—and the corresponding potential for outsized errors—we believe moving forward in a methodical way is justified.
- Additional processing. Carbon intensity pathways should account for energy used when (and if) refineries isomerize co-processed fuels to improve cold flow performance.
- Emissions. We have not been able to find published literature regarding emissions and public health impacts for co-processed fuels. Since the technological process is the same as that which creates CARB diesel and the finished product is chemically indistinguishable from CARB diesel, we are not convinced that the environmental and public health impacts of co-processing should be assumed to be positive.
- Technical properties. Potential concerns about cold-flow performance, stability, and incomplete refining could require additional test parameters and limits to be included.

- Indirect effects. When bio-based feedstocks are comingled with fossil feedstocks, refiners should supply CARB with enough verifiable information to enable a full assessment of the indirect effects of co-processing on other refinery operations. This information should be made available in the same manner that Tier I framework biofuels have made information publicly available.
- ASTM specification. Co-processed renewable diesel does not have an ASTM fuel or blend specification. We believe parameters for co-processing diesel fuel may be needed to help demonstrate complete processing and a fit-for-use fuel.
- Alternative Diesel Fuel (ADF) regulation. Co-processed renewable diesel is a new fuel that should go through the ADF process like biodiesel has—and other renewable diesel replacement fuels will in the future. This step would ensure that emissions, public health, and operability data is available to CARB and the public for evaluation. (NBBCABA1_29-12a)

Comment: Co-processing of biological feedstocks in existing petroleum refineries can be a viable option for obligated parties to participate in the LCFS. It is important to recognize the complex nature of refinery operations and the fact that low carbon feedstocks are anticipated to make up only a fraction of the refinery inputs. This will make accurate quantification of the carbon intensity of the finished fuels produced from co-processing particularly challenging. Where bio-based feedstocks are comingled with fossil ones, refiners must supply CARB with enough verifiable information to enable a full assessment of both the emissions of co-processed fuels and the indirect effects of co-processing on other refinery operations. (COALITION1_107-6)

> **Agency Response:** See response to NBBCABA3-FF4-9 in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations. Please see also Response J-12.2 in this chapter.

J-12.2. **Comment:** Co-processing of low CI fuels in a petroleum refinery is a novel means of utilizing existing infrastructure and technologies to support the goals of LCFS. The refining industry has a history of people with very strong technical skill required to operate, optimize and manage facilities. Based on this experience, we support the use of mass/carbon balance methodologies to accurately and reliably predict gasoline and diesel yields attributable to co-processing low CI fuels at levels less than ten percent of total process unit charge rates. It is also our opinion that use of C14 is not applicable for all co-processing conditions and will result in inaccurate CI calculations of the resulting fuel. To note, this opinion was presented as recently as the February 7, 2017 Public Working Meeting by James Rekoske of Honeywell/UOP and Michael Talmadge with Helena chum of NREL. (ANDEAVOR1_67-6).

> **Agency Response:** Staff supports continued efforts of petroleum refiners to co-process low-CI and renewable feedstocks to produce low carbon fuels. The issue of C14 analysis, while potentially important for quantification of yields from such projects, is beyond the scope of these regulatory amendments.

J-13. ***Book-and-Claim Accounting/Renewable Determination***

Comment: Electrical power is an important input in all aspects of hydrogen production, compression, liquefaction, distribution, and dispensing. Electricity is the primary input when hydrogen is produced by electrolysis from water, but electrical power is also a significant source of energy for compression, liquefaction, pumping, and refrigeration of hydrogen produced by any method. Therefore, it is important that the LCFS regulations recognize renewable electricity as such whenever it is used in a hydrogen pathway. For example, in proposed Section 95486.1, the credits available for improvements in the CI of electricity used for the production of hydrogen should also be available for improvements in the CI of electricity used for compression, liquefaction, distribution or dispensing:

> **Section 95486.1(e)(2):** *Time-of-Use Pathways for Hydrogen Production. An entity can generate credits, in addition to credits generated pursuant to subsection (1), above, for improvements in the CI of electricity used for electrolysis to produce hydrogen**, or for hydrogen compression, liquefaction, distribution or dispensing,** due to time of use pursuant to section 95488.5 and the credit calculation in section 95486.1(c)(2)(B), where:*
>
> *Electricity is the total quantity of low-CI electricity supplied to the electrolyzer for production**, or used for hydrogen compression liquefaction, distribution or dispensing.***

Similarly, in proposed Section 95488.8(i)(1) the proposed text should be broadened to include reference to hydrogen compression, liquefaction, distribution and dispensing:

> **Section 95488.1(i)(1):** *Book-and-Claim Accounting for Renewable or Low-CI Electricity Supplied as a Transportation Fuel or Used to Produce Hydrogen. Reporting entities may use indirect accounting mechanisms for renewable electricity to reduce the CI of electricity supplied as a transportation fuel**,** for hydrogen production through electrolysis, **or for hydrogen compression, liquefaction, distribution or dispensing,** provided the conditions set forth below are met…*

A parallel change should also be made in proposed subsection (i)(1)(a):

> **Section 95488.1(i)(1)(A):** *Reporting entities may report electricity dispensed to electric vehicles or as an input to hydrogen production**, compression, liquefaction, distribution or dispensing**…*

A similar change should be made in Section 95488.10:

> **Section 95488.10(a)(4):** *Any fuel pathway holder, including a joint applicant, who is not subject to site visits by a third party verifier, whose pathway involves the use of renewable or low-CI process energy, must submit invoices for that energy to the AFP. Additionally, for any electricity that is used to reduce carbon intensity of electricity for EV charging**,** ~~or~~ hydrogen production via electrolysis, **or hydrogen compression, liquefaction, distribution or dispensing,** the pathway holder must*

upload records demonstrating that any RECs generated were retired in WREGIS for the purpose of LCFS credit generation.

Finally, a similar change should be made in the LCFS's reporting requirements:

Section 95491(d)(4)(D): *For hydrogen reported with a pathway that claims carbon intensity reductions for shifts in time of electricity use for electrolytic hydrogen production,* ***compression, liquefaction, distribution or dispensing,*** *the quantity of electricity (in kWh) used to produce****, compress, liquefy, distribute and dispense*** *hydrogen for each time-of-use window must be reported with transaction type FCEV Fueling – TOU.* (AL1_39-1)

Agency Response: Renewable (or low-CI) electricity that is used at any stage in the life cycle of a fuel can be recognized in the determination of CI, but additional flexibility is provided for electricity that is used directly as a transportation fuel or for hydrogen production by electrolysis. The text proposed by the commenter does not align with the regulation's requirement for low-CI process energy to be directly supplied. Indirect, or book-and-claim, accounting for renewable or low-CI energy is recognized under the LCFS only for feedstocks or when the input is used directly as a fuel, not process energy. Any renewable electricity used as process energy for compression, liquefaction, and dispensing, must be supplied directly to the facility that compresses, liquefies, or dispenses the fuel in order to be accounted for in the determination of CI.

Consistently, in steam methane reformation (SMR), a portion of the methane is used as feedstock (that is, the hydrogen molecules are taken from CH_4) while another portion of the methane is combusted for process energy to produce steam. In SMR, only the methane that is used as feedstock can be matched with renewable attributes of biomethane to be accounted for with the associated CI of biomethane. Any biomethane that is combusted for use as process energy in SMR must be supplied directly to the facility that converts the methane to hydrogen.

Directly-supplied low-CI process energy will be accounted for in CI determination, but does not impact the renewable content determination which is assessed on the basis of feedstock energy rather than life cycle energy.

J-14. *Indirect Land Use Change*

J-14.1. *Assessment of Land Use Change Carbon Intensity Values*

Comment: *NextGen Urges CARB to Direct More Resources Towards Improving Research Into Indirect Effects of Fuel Production, Especially Indirect Land Use Change*

The scientific foundation of the LCFS is Life Cycle Analysis, which is itself, a comparatively new method of analysis. New data and analytical techniques emerge regularly, as well as a better understanding of the strengths and limitations of this technique. Recent authors have suggested that a focus on direct analysis of material

and energy flows within the narrowly-described boundaries of a production process (often called "attributional analysis") may overlook many critical impacts and yield an inaccurate assessment of actual emissions.[16] This is especially true with regard to effects that are mediated through domestic or international markets, where production processes may compete for resources in ways that are difficult to accurately characterize. These indirect effects, especially indirect land use change (iLUC), can result in significant emissions, particularly from biofuel production.

[16] e.g. Plevin, R. J., Delucchi, M. A. and Creutzig, F. (2014), Using Attributional Life Cycle Assessment to Estimate Climate-Change Mitigation Benefits Misleads Policy Makers. Journal of Industrial Ecology, 18: 73-83. doi: 10.1111/jiec.12074

We believe that CARB, and the LCFS Program Staff, have done an excellent job at assessing the full range of extant literature on indirect effects and iLUC and the LCFS is on the cutting edge of regulatory sophistication where this is concerned. We must acknowledge, however, that the literature on indirect effects is far from complete and we cannot rule out the possibility that the current iLUC values used by the LCFS substantially underestimate actual effects.

NextGen urges CARB to dedicate more research support towards a better understanding of domestic and international markets for feedstocks used in low-carbon fuel production. In particular, we feel more attention is necessary to understand indirect effects and cross-product substitutions in the edible and inedible oil and tallow market These fuels comprise the preferred feedstock for biodiesel, renewable diesel and alternative jet fuel production. If CARB's assessment of indirect effects is inaccurate, the LCFS could be supporting inefficient, or harmful environmental and economic outcomes.

If updated research demonstrates that previous fuel pathways inaccurately assess actual emissions, CARB should adjust existing fuel pathways to match updated data. We recognize that retroactively changing fuel pathway CI scores may impact financial stability of producers of affected fuels and are willing to support a gradual, or phased-in transition to more accurate CI values. A science-based program like the LCFS cannot, however, support credit generation based on inaccurate data indefinitely. (NEXTGEN1_124-50)

> **Agency Response:** Every periodic update to life cycle analysis in the LCFS attempts to use the latest data and science as assessed by CARB's expert staff. Therefore, staff does not agree with the commenter that credit generation is supported by inaccurate data. The Land Use Change analysis framework for the regulatory update in 2015 considered cross-product substitutions of crop-based feedstocks and derivatives used in biofuel production. However, the GTAP model database used reflected the global economy when negligible quantities of inedible oil and tallow were used in biofuel production which limited contributions of these feedstocks to impact cross-product substitutions. Staff is committed to periodically updating life cycle analysis modeling tools and is committed to revisiting indirect effects analysis in a future rulemaking. Harmonizing attributional and consequential impacts in the life cycle analysis of transportation

fuels will also be considered in a future rulemaking. If such a review suggests a revision to the current treatment of feedstocks (including tallow, inedible oil), this will be communicated to stakeholders during the regulatory update period ensuring industry is made aware of impacts to pathway CIs for fuels produced from these feedstocks. Staff is aware of the potential for disruption of financial investments in fuel production facilities if regulatory actions were taken to include such effects without a rigorous and exhaustive public process.

J-14.2. Multiple Comments: *Sufficient Evidence to Modify Land Use Change Carbon Intensity Values*

Comment: ARB Failed to Update Indirect Land Use Emissions in the LCFS

The carbon intensities of biofuels include estimated emissions for indirect land use changes, generally referred to as "ILUC." Including estimates of these emissions in the carbon intensities of biofuels by ARB has been controversial, because the ILUC estimates for biofuels are very uncertain, and require a myriad of input information and different models to estimate. In prior efforts to determine ILUC, the input information needed to make these estimates was not available, and the models used to make these estimates were in their infancy.

ILUC emissions should not have been included in the LCFS by ARB in the first place, as the science has not matured to the point where it included most of the significant input drivers. For example, the ILUC estimates for biofuels used by ARB in the current and previous LCFS regulation do not include any effects for multi-cropping or the use of idle cropland. These and other factors have been pointed out to ARB since the advent the LCFS regulations. Economists have been developing methods of including these factors in ILUC estimates, and their inclusion into ILUC estimates has had a dramatic effect at reducing initial biofuel ILUC estimates.

Indeed, it is now widely recognized that early efforts to calculate ILUC were significantly overstated. As the methods for estimating these emissions have started to mature somewhat, the ILUC estimates for various biofuels have fallen significantly. For example, an early estimate of ILUC for corn ethanol was 106 g/MJ.[1] ARB's first estimate of the ILUC of corn ethanol was 30 g/MJ.[2] The ILUC of corn ethanol in the current regulation is 19.8 g/MJ.[3]

[1] *Use of U.S. Croplands for Biofuels Increases Greenhouse Gases Through Emissions from Land-Use Change*, Searchinger, T., Heimlich, R., Houghton, R.A., Dong, F., Elobeid, A., Fabiosa, J., Tokgoz, S., hayes, D., Yu, T., Science, 29 Feb 2008: Vol. 319, Issue 5867, pp. 1238-1240DOI: 10.1126/science.1151861

[2] Final Regulation Order for Low Carbon Fuel Standard, January 12, 2010, Table 6, page 47, https://www.arb.ca.gov/regact/2009/lcfs09/finalfro.pdf

[3] Final Regulation Order for Low Carbon Fuel Standard, Table 5, page 60, https://www.arb.ca.gov/regact/2015/lcfs2015/lcfsfinalregorder.pdf

Substantial evidence no longer supports an ILUC of 19.8 g/MJ for corn ethanol. The consensus among technical experts is that these ILUC values remain overstated, and should be further reduced. Specifically, current estimates for the ILUC of corn ethanol in the U.S. range from 7.8-12 g/MJ.[4,5]

[4] Argonne GREET2016 Model, https://greet.es.anl.gov/

[5] *The impact of considering land intensifications and updated data on biofuels land use change and emissions estimates*, Figure 4, F. Taheripour, X. Zhao, and W. Tyner, Biotechnology for Biofuels, DOI.1186/s13068-017-0877-y, July 2017

Despite this new data, in the proposed LCFS amendments, ARB has updated the direct emission estimates such as the farming and fertilizer emissions, but failed to update the indirect estimates. The ILUC estimates are a very significant proportion of total emissions for biofuels. For example, the total carbon intensity for corn ethanol is now around 68 g/MJ, depending on various inputs from the corn ethanol plant and the distance of that plant from California. The ILUC estimate for corn ethanol is 19.8 g/MJ, which is 30% of the total carbon intensity. ARB has therefore taken a "piecemeal" approach to updating the carbon intensities to the various biofuels. With respect to updating the ILUC estimates, the ISOR states:

> Staff has not observed sufficient evidence in the literature to justify modifying the LUC CI values for the proposed regulation.[6]
>
> [6] Initial Statement of Reasons for LCFS, Page III-86.

This statement is simply not true. Growth Energy, in its comments on the existing regulation, referenced significant work by the Babcock and Iqbal at the University of Iowa that showed significantly less global land conversions due to biofuel policies than previous thought and estimated by the ARB staff.[7,8] Their analysis showed that land "intensification", that is, the use of existing cropland through multi-cropping and the use of idle land, was much more prevalent than land "extensification", where land such as forest is converted to cropland. ARB's ILUC estimates were primarily based on land extensification. Growth Energy also recommended methods of incorporating UI's analysis into ARB's estimates, and developed preliminary estimates of ILUC using the Babcock/Iqbal work.

[7] Growth Energy's Response to the Notices of Public Hearings Dated December 16, 2014 2015 Cal. Reg. Notice Reg. 13, 45 (January 2, 2015), February 17, 2015, Appendix A.

[8] Using Recent Land Use Changes to Validate Land use Change Models", Babcock and Iqbal, Staff Report 14-SR- 109, Center for Agriculture and Rural Development, Iowa State University, www.card.iastate.edu.

The work by Babcock/Iqbal was also reviewed extensively by Global Trade Analysis Project (GTAP) researchers at the University of Purdue. The GTAP economic general equilibrium model is used by ARB to estimate ILUC values for biofuels for the LCFS. Purdue researchers used the Babcock/Iqbal methods and data to update the GTAP model, and the Purdue researchers also updated many other significant factors in the GTAP model, including updating the GTAP model database from calendar year 2004 to calendar year 2011.[9] Their work was published in a peer-reviewed journal publication in July of 2017.[10] Their work showed that, using ARB's AEZ-EF model in conjunction with GTAP to estimate emissions associated with the various land use changes, corn ethanol ILUC dropped from 23.3 g/MJ to 12 g/MJ, with the incorporation of (1) land intensification effects, and (2) the change to the 2011 database.[11] The reduction in corn ethanol ILUC associated with these model updates is 48%. Assuming that this percent reduction in ILUC obtained by Purdue with the two major model modifications can be applied to ARB's current ILUC value for corn ethanol of 19.8, gives a value of 10.3 g/MJ. Therefore, if Staff had used the available updated GTAP model to estimate new ILUC

values for biofuels using its 30 sensitivity scenarios, it is likely ARB would have developed an estimate of around 10g/MJ for corn ethanol. There would have been significant changes in the ILUC values for other biofuels as well, since land intensification and the change in database would likely have affected all biofuel feedstocks.

[9] The current ARB ILUC estimates are based on the 2004 calendar year database.

[10] *The impact of considering land intensifications and updated data on biofuels land use change and emissions estimates*, F. Taheripour, X. Zhao, and W. Tyner, Biotechnology for Biofuels, DOI.1186/s13068-017-0877-y, July 2017.

[11] Purdue ran a single scenario to estimate these values. For the current regulation, ARB ran 30 scenarios with varying inputs and averaged the 30 results to obtain the 19.8 g/MJ for corn ethanol.

The technical documents supporting the ISOR and the EA also do not recognize ongoing efforts by technical experts to resolve known issues relating to the overstatement of the ILUC value for corn ethanol, and to incorporate more recent facts into these analysis. For example, the current ILUC for corn ethanol does not reflect accurate facts because it is based on year 2011 conditions, which correspond to a drought year in the US which negatively impacted crop yields. This is important because higher yields mean that less land use change is required to satisfy the new demand resulting in lower ILUC values. The 2011 corn yield was 146.8 bu/acre, which was actually lower than the 2004 yield of 160.3 bu/acre and one of the reasons why the ILUC emissions went up when the 2011 database was used. The 2017 corn yield was 176.6 bu/acre.

The GTAP team is also investigating the response of the livestock sector to increased biofuel production in the model to ensure that the model is consistent with the observed recent changes in that sector. In particular, there has been a major shift in livestock production in the last 40 years in the US from beef to poultry. Because of the much lower land requirements of poultry than beef, much agricultural land has been freed up for other agricultural uses, and this has led to lower land use transformation than previously thought. [12]

[12] *Technological progress in US agriculture: Implications for biofuel production*, Taheripour, F., Department of Agricultural Economics, Purdue University, presented at National Biodiesel Board Webinar, March 15, 2018.

Therefore, our conclusion is that (1) the existing ILUC value for corn ethanol of 19.8 g/MJ is no longer supported by substantial evidence, (2) the literature demonstrates the ILUC values should be updated in time for the proposed amendments to the LCFS regulation, and (3) if the values had been updated by ARB, they would have been much lower than the values from the previous regulation. (GROWTHENERGY1_B4-108)

Comment: The California Resources Board (CARB) proposes to keep the current LUC CI values because "staff has not observed sufficient evidence in literature to justify modifying LUC CI values." For the following reasons, FHR believes the sufficient evidence exists to support modifying LUC CI values.

During the 2015 LCFS Re-adoption rulemaking process, CARB staff committed to undertaking a review of the latest scientific data for LUC and update the LUC values for

the appropriate biofuels. According to the literature citations provided throughout the 2013-2015 LCFS public workshops, and other regulatory documents (including the 2015 LCFS Re-adoption Initial Statement of Reasons (ISOR) and Final Statement of Reasons (FSOR)), the scientific data was based on literature published prior to 2014. From this review, CARB updated the LUC values for 6 biofuel feedstocks during the 2015 LCFS Re-adoption.

Since 2014, there have been numerous peer-reviewed publications, dissertations, and other scientific literature, focused on various aspects of LUC related to biofuels, as listed within Appendix A. There have been additional peer-reviewed publications and model updates that were not included in any aspect of the 2015 rulemaking, as presented in Appendix B. FHR contends that now is the appropriate time for CARB staff to conduct a review of these additional publications and global economic model updates during the upcoming rulemaking process. FHR's more detailed comments are as follows:

1. **Comment:** ***CARB should use the latest available scientific data, specifically GTAP Version 9 (Baldos, 2017) with baseline data from 2011, to assess the impacts on LUC values. CARB should also include the biofuels update to GTAP 9 (Taheripour, 2016).***

   Since the conclusion of the 2015 LCFS Rulemaking, GTAP Version 9 has been released with base year 2011 data, providing a more accurate depiction of land-use than the previously used base year 2004 data, when crop-based biofuels were being produced at a fraction of 2011 production levels.

   Please also make note of CARB's response to PR-26 within the 2015 LCFS Re-adoption FSOR which acknowledged the need for updates and the potential affect the updates would have in the LUC estimate: "Purdue is currently in the process of updating the baseline to a 2010 timeframe. When the update is completed, CARB will consider updating the LUC analysis. Refining the baseline of the model may change the LUC estimate."

2. ***CARB should use the Carbon Calculator for Land Use Change (CCLUB) from Biofuels Production in the assessment of the impacts on LUC values (Dunn, 2016).***

   New scientific research has been released since the 2014 timeframe. This research has undergone rigorous independent peer reviews and was incorporated into the modeling of the latest iLUC values using CCLUB16 and Winrock. These updates provide results, as determined in the recent report published for the USDA (Flugge, 2017) that are superior to those calculated with the current AEZ-EF model.

   Based on our review of CCLUB16, the database and elasticity values used to assess land use area changes and carbon stock factors provide carbon impacts closer to an IPCC Tier 3. FHR believes that the CCLUB16 model addresses the

problematic assumptions identified by CARB within the FSOR to the 2015 LCFS Re-adoption rulemaking.

FHR requests CARB to use the referenced sources and models included in Appendix A and B respectively to produce revised iLUC values that are more representative of actual, real-world emissions as published by various experts in this field. (According to Flugge, the iLUC for corn ethanol should be 5,913 g CO2e/MMBTU.) (FHR1_18-1)

Comment: a. RFA again encourages CARB to adopt the ILUC values from the latest Argonne GREET model, as Oregon DEQ has done for its state's Clean Fuels Standard. We continue to believe the science underlying the Argonne GREET model ILUC factors is more robust and current than the science supporting CARB's current ILUC factors. (RFA1_80-12)

Comment: The Initial Statement of Reasons indicates that "Staff has not observed sufficient evidence in literature to justify modifying the LUC CI values for the proposed regulation[14]. Updates to LUC CI values may be considered for future rulemakings, if appropriate."

[14] Staff Report: Initial Statement of Reasons, page III-86.

In our view, substantial progress has been made on the issue of indirect land use change since CARB last considered it in 2015. For example, the previous version of the Global Trade Analysis Project (GTAP) model used by CARB relied on a database that represented the world in 2004. Scientists at Purdue University have since integrated data through the year 2011. GTAP is now more capable of modeling the world in which the current biofuels industry operates. In our view, this alone makes new GTAP runs more accurate and worthy of full-scale review by CARB.

Beyond the 2004 to 2011 updates, the increase in data now available provides more evidence to help validate and calibrate the model. The enhanced analysis and structural improvements incorporated since 2015 by Purdue could not have occurred earlier because the data simply did not exist. We have referenced for your review several papers that have been published in various scientific journals[15]. These papers elaborate on advances made in the field of indirect land use change since CARB's last review in 2015.

[15] Taheripour F., Zhao X., and Tyner W. (2017) "The Impact of Considering Land Intensification and Updated Data on Biofuels Land Use Change and Emissions Estimates," *Biotechnology for Biofuels*, 10: 191.

Taheripour F., Cui H., Tyner W. (2017) "An exploration of agricultural land use change at the intensive and extensive margins: Implications for biofuels induced land use change," In Z. Qin, U. Mishra & A. Hastings (Eds.), *Bioenergy and Land Use Change*: American Geophysical Union (Wiley).

Chen, R., Qin, Z., Han, J., Wang, M., Taheripour, F., Tyner, W. O'Connor, D., and Duffield, J. (2018). Life cycle energy and greenhouse gas emission effects of biodiesel in the United States with induced land use change impacts. *Bioresource Technology, 251*, 249-258. doi: 10.1016/j.biortech.2017.12.031.

Finally, CARB is to be commended for setting these developments in motion by investing in the GTAP model and by helping develop the methodology used to assign iLUC and carbon intensity values within the LCFS. The science has continued to advance and that is due in no small measure to CARB's investment and stewardship.

Since 2015, the reliability and accuracy of the GTAP-BIO model has improved exponentially. For this reason, we believe CARB should embark upon a process to update these values in 2019. (NBBCABA1_29-27)

Agency Response: Staff is committed to an accurate assessment of LUC effects and has responded to these comments below.

CARB conducted an extensive public process between 2012-2015 to update LUC values for biofuels. The update utilized best available data and economic and scientific information and resulted in revisions to LUC values from the original values published in 2009. Several updates to reflect feedback from the Expert Working Group (EWG) were incorporated into the model. The database was updated to reflect 2004 data in the GTAP model. A separate carbon emissions model called the Agro-Ecological Zone-Emissions Factor was developed and used in combination with the GTAP model to account for advances in soil carbon data and science. In addition to GTAP results, a Monte Carlo framework was used to inform CARB of the potential uncertainty in LUC values. The results from the updated LUC analysis was also subject to a peer-review by experts in this field.

A major argument raised by commenters is that recent changes to the GTAP model by Taheripour and Tyner, and the use of the CCLUB model in place of the AEZ-EF model, have resulted in lower LUC emissions estimates than are currently used in the regulation. Many of these changes, however, are based on arguable assumptions or methods. Importantly, changes that were requested by the LCFS expert workgroup and subsequently by CARB that would likely increase the LUC emissions estimate have yet to be implemented in GTAP. The most notable of these is the ability to bring non-commercial forest into production, a capability common to other models used to estimate ILUC, including: MIT's EPPA, IFPRI's MIRAGE, IIASA's GLOBIOM, and PNNL's GCAM. In GTAP-BIO, all forestry land is treated as producing timber, so the conversion of any forestry land results in a decline in timber output from the converted area, creating pressure elsewhere to increase timber production, counteracting some of the forest removal in terms of carbon emissions. If non-commercial forest land were available for conversion, this market-mediated effect would not occur, most likely resulting in an increase in LUC emissions.

In support of lowering ILUC values, commenters have cited the 2014 report by Babcock and Iqbal while failing to note important caveats in that report, including this statement: "Despite the large discrepancies between model predictions and the actual land use changes that have occurred since 2004 it simply is not possible to conclude with certainty that the model predictions have been proven wrong and should be disregarded." This is because LUC modeling requires comparing a modeled world with some amount of additional biofuel to a counterfactual world without that amount of biofuel. Babcock and Iqbal further note that "it could be that the amount of actual land reduction that would have occurred in the EU and Canada would have been much larger without the

commodity price boom and that if actual land use changes were calculated relative to what would have happened without the price impact then the GTAP model predictions would be consistent with what we observe. Thus, without being able to observe the alternative history that did not contain the commodity price boom, it is not possible to conclude with certainty that the model predictions were wrong." The authors therefore cautioned against interpreting their work as disproving modeled outcomes.

As in prior rulemakings, commenters suggest the adoption of the Carbon Calculator for Land Use Change (CCLUB) model in the LCFS. However, issues with the CCLUB model identified by CARB in the previous rulemaking have not been satisfactorily addressed, several of which continue to be listed as potential future modeling changes in the CCLUB documentation.[50] For example, estimates of uncertainty have not been provided for CCLUB model results, in contrast to the robust uncertainty analysis conducted for the AEZ-EF model. In addition, the CCLUB model takes a simple average of emissions factors for aggregated regions, rather than weighting the average by the size of each country, resulting in less robust international land use change estimates than those from the AEZ-EF model. It is also not clear why the commenter states that the CCLUB land use change results identified in Flugge et al.[51] are superior to results from the AEZ-EF model. In addition, Malins[52] calls into question many of the conclusions made in Flugge et al. as a result of several substantive concerns. Examples of such concerns include misquoting RFS emissions impact results, confusing control and reference scenarios from the RFS Regulatory Impact Analysis, and at times ignoring or undervaluing data that may lead to an increase in GHG emissions from corn ethanol (Malins).

Another concern with the CCLUB model is that has not undergone a level of peer review like that of the AEZ-EF model. Papers relying on the model have been peer-reviewed, but this is not the same as a comprehensive review of the model itself. CCLUB includes several questionable assumptions that reduce the estimated carbon emissions, including (but not limited to):

a. A portion of the land treated as commercial forest in GTAP is treated as "young forest / shrubland" when accounting for carbon emissions, reducing the carbon emissions from conversion.

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[50] Carbon calculator for land use change from biofuels production (CCLUB) users' manual and technical documentation, (No. ANL-/ESD/12-5 Rev. 4). Argonne National Laboratory, Argonne, IL (United States). Dunn, J. B., Qin, Z., Mueller, S., Kwon, H. Y., Wander, M. M., & Wang, M. (2017).

[51] A Life-Cycle Analysis of the Greenhouse Gas Emissions of Corn-Based Ethanol. Washington, DC, Report prepared by ICF under USDA Contract No. AG-3142-D-16-0243. January 12, 2017. Flugge, M., J. Lewandrowski, K. et al. (2017). Available: https://www.usda.gov/oce/climate_change/mitigation_technologies/USDAEthanolReport_20170107.pdf.

[52] Navigating the maize, A critical review of the report 'A Life-Cycle Analysis of the Greenhouse Gas Emissions of Corn-Based Ethanol', *Dr Chris Malins, July 2017*

b. Similarly, all conversion to cropland in CCLUB is treated as conversion to corn, whereas GTAP reports changes in a variety of crops.

c. Using simple rather than area-weighted averaging of soil carbon densities across counties. Counties differ substantially in area, so ignoring this can substantially skew the results.

d. As noted in the 2017 CCLUB documentation[57], the land use history for cropland-pasture—the dominant land source for extensification in GTAP-BIO—is assumed to be "50 years as cropland, followed by 25 years of pasture and the 25 years of cropland. Actual land use history may include more frequent changes between these two land uses." The assumption that all cropland-pasture (CP) has been in crops for 25 years is equivalent in terms of soil carbon to treating CP effectively as carbon-depleted cropland. This assumption eliminates the carbon penalty for converting CP to cropping. Indeed, in CCLUB converting CP results in carbon sequestration rather than loss—a result not seen in any other model we know of.

e. CCLUB uses different methods for the domestic U.S. and the rest of the world, and when the other methods employed for the rest of the world are used domestically as well, the results increase substantially.

The commenter directs attention to an updated GTAP model available in 2017 and questions why CARB did not consider updates to ILUC analysis for the current rulemaking. Completing a comprehensive review of updated data and land use science coupled with an extensive public process to inform stakeholders of changes to the modeling framework is likely to require between 36 to 48 months. The consideration of using the updated July 2017 model referenced by the commenter would significantly delay the current rulemaking process, and staff doesn't believe sufficient new information has been brought forward to warrant such a delay. However, staff maintains its commitment to periodic review and assessment of land use change emissions. Staff is committed to continuing review of indirect effects including land extension/intensification, multi-cropping, and cross-product substitutions for various feedstocks used in fuel production after the completion of this round of rulemaking. In a future rulemaking, staff will review updates to relevant models and incorporate relevant suggested modifications by stakeholders, conduct extensive stakeholder interactions and refine LUC values, if appropriate to do so, for all crop-based biofuels, and possibly account for other indirect effects, if necessary.

J-15. *Missing Data*

Comment: Missing data Section 95488.8(k) requires entities to submit an alternate method of reporting for approval by the Executive Officer. However, the regulation does not stipulate what is considered missing data. Some instruments can obtain and record data on a frequent interval. What is the maximum percentage of time a meter can be offline before it is considered missing data? (VALERO1_69b-9)

Agency Response: Section 95488.8(k)(1)(B) implicitly defines missing data as any data reported using a measurement device that fails the calibration requirement of 95488.8(j), and which subsequently cannot be demonstrated as being accurate within +/-5 percent. The proposed regulation does not prescribe thresholds of data gap sizes that would or would not constitute missing data, but entities are expected to notify CARB in the event that data from a measurement device become unavailable, or in the case of a force majeure event (described in 95488.8(k)(3)).

K. Crude Oil and Innovative Crude Production Method Provisions

K-1. Multiple Comments: *Support for the Proposed Amendments to the Innovative Crude Production Method Provisions*

Comment: We support the goals of the amendments and particularly applaud the changes to opt-in rules regarding crude produced using innovative methods. Allowing the Project Operator to generate credits under the innovative crude section substantially simplifies the implementation of revenue-sharing agreements. (EF1_3-1a)

Comment: We support CARB's continuing efforts to improve the LCFS program in general, and the Innovative Crude provisions specifically.

…

We appreciate CARB's treatment of innovative crude production methods, and its recognition of the value of reducing emissions associated with crude oil extraction. We believe that the innovative crude provisions are appropriate given the program's fundamental focus on fuel life cycle emissions, and provide a price signal for projects which will deliver economic growth in California while reducing both criteria pollutants and GHG emissions. (GLASSPOINT1_65-2)

Comment: We would like to underscore the necessity of long-term stability of the program for investments to be made in emissions-reducing projects. We look forward over the next decade and beyond to a steady-state implementation of the program. (GLASSPOINT1_65-3)

Comment: GlassPoint specifically supports the proposed revision to LCFS credit calculation for solar steam under the Innovative Crude provisions, including:

- The additional bins for higher steam quality; and
- Updated emissions values using OPGEE v2.0.

The inclusion of the additional bins will more accurately track the enthalpy and emissions per barrel displaced for specific California operations. GlassPoint believes the proposed values correspond to avoided emissions under current industry practices… (GLASSPOINT1_65-4)

Comment: GlassPoint believes the administrative aspects of this program as are important as the technical issues discussed above.

In addition to the credit calculation enhancements, GlassPoint strongly supports the concept of "allowing third-party co-applicants (e.g. solar steam or solar electricity providers) to opt-in and receive credit upon written agreement with crude producer". As we have discussed numerous times, this simple administrative opportunity will have significant value in the commercial marketplace, particularly for projects using third-party finance. (GLASSPOINT1_65-6)

Comment: The LCFS regulations allow for program participants to receive LCFS credits for utilizing renewable electricity in both conventional fuel refinery operations and crude production. This is an important policy to further drive private adoption of renewable energy to help meet the state's climate goals. (SUNPOWER1_70-1)

Comment: We support CARB's efforts to improve the Innovative Crude provisions within the existing LCFS program. The Innovative Crude provisions recognize and credit the potential efficiencies that can be gained in our industry. Specifically, we support the proposed revision to the credit calculation methodology that adds additional bins for higher steam quality levels. The inclusion of these additional steam quality bins will more accurately track the enthalpy and emissions per barrel for California operations. CIPA supports basing these new values on the most robust science, as well as, industry standards. (CIPA1_71-2)

Comment: CIPA *supports* the new provisions allowing for joint application on projects and the ability of producers to opt into transferring credits to the provider of solar steam or solar electricity. These additional administrative options will help provide the business climate needed to incent more projects. (CIPA1_71-3)

> **Agency Response:** Staff appreciates the support for the proposed changes to the innovative crude provision and agrees that long-term stability of the program is important for investments to be made.

K-2. *Crude Oil Provisions*

K-2.1. *Oil Production Greenhouse gas Emissions Estimator Model*

K-2.1a. **Comment:** We also appreciate the breadth and depth of work which has gone into the OPGEE assessment tool to accurate capture the energy footprint from the production, processing, and transport of crude petroleum, including the addition of solar steam to the model. (GLASSPOINT1_65-5)

> **Agency Response:** Staff appreciates the support for the proposed changes to the OPGEE model.

K-2.1b. **Comment:** Finally, as we have discussed with staff, we recommend three changes to certain default OPGEE parameters for SJV Heavy Crudes:

- Reservoir Pressure: all values should be less than 100 psia
- Wellhead Pressure: use 100 psia instead of 1000 psia
- Steam Quality: actual values range between 50-70%; CARB currently assumes 80%

We have had productive conversations with staff on these and other OPGEE inputs and look forward to continuing that dialogue. We believe that there are improvements that can be made between now and the final version to be approved in September. (CHEVRON1_112-26)

Agency Response: In response to this comment, staff has proposed that default parameters for reservoir pressure and wellhead pressure be revised in OPGEE v2.0 for California heavy oil fields. Staff has also proposed that the default steam quality value be changed from 80 percent to 70 percent based on consultation with California thermal recovery industry engineers. Lower steam quality values can be entered by users for particular projects if desired.

K-3. *Innovative Crude Production Method*

K-3.1. *Additional Innovative Crude Methods and Technologies*

K-3.1a. **Comment:** Innovative Methods for producing crude should be technology neutral and should recognize the use of biogas as a GHG reduction fuel. CIPA believes that significant GHG reductions could be achieved if the use of Renewable Natural Gas (RNG) was recognized in the innovative crude sections of the Regulation. There are significant sources of RNG in California's Central Valley operating within short distances of significant oil and gas production fields. If the LCFS rule allowed for book and claim mechanisms to get this RNG to oil fields, there could be substantial investment in new dairy projects from the oil/gas industry. This effort would be complementary to the State's Short-Lived Climate Pollutant efforts and entirely consistent with the RNG book and claim provisions of the existing LCFS, as well as, the book and claim proposal for renewable electricity crediting for electric vehicle charging. *CIPA believes that adding RNG to the list of eligible activities in Section 95489(c)(1)(A) is appropriate at this time, and that a simplified calculation could be added similar to that for solar steam.* (CIPA1_71-4)

Agency Response: In response to this comment, staff has proposed adding renewable natural gas (RNG) or biogas energy as an eligible innovative crude technology. However, staff's proposal requires that RNG or biogas must be physically supplied directly to the crude oil production facilities to qualify for the LCFS credits. The requirement for physical delivery of the RNG or biogas is consistent with accounting elsewhere in the LCFS where RNG or biogas is used for process energy needs at alternative fuel facilities or at petroleum refineries.

K-3.1b. **Comment:** In addition to biogas, CIPA believes now is the time to expand the Innovative Crude provisions to all for a wider band of possible GHG reduction technologies, including geothermal energy, ocean wave energy, or some other innovative energy source or efficiency not considered under the current regulation. There should also be an option for the Executive Officer to review and approve other technologies not yet discussed. This option would allow for additional innovation without having to reopen the regulation. These additions will allows the Board flexibility and discretion to use other CI reduction methods to meet California's LCFS goals. (CIPA1_71-5)

Agency Response: In response to this comment, staff proposed to add geothermal, ocean wave, ocean thermal, and tidal current energy generation as eligible innovative technologies in the First Notice of Public Availability of

Modified Text and Availability of Additional Documents and Information posted on June 20, 2018. However, in the Second Notice of Public Availability of Modified Text and Availability of Additional Documents and Information posted on August 13, 2018, staff removed these energy sources from the proposal because the environmental analysis did not explicitly analyze the use of such technologies in petroleum extraction. Staff will consider adding this in a future rulemaking when we have adequate time to evaluate the impacts of these technologies when used in conjunction with oil extraction. Staff believes that it is important for these innovative crude method technologies to go through the complete rulemaking process prior to being approved for credit generation.

K-3.1c. Multiple Comments: *Adding Additional Technology and Efficiency Options*

Comment: Similar to refinery investment credit projects, we believe there are several additional technology and efficiency options that should be added to the innovative crude section, including:

- Improvements in process efficiency including advanced control systems, digitalization, etc.
- Improvements in equipment energy efficiency, including facility upgrades/retrofits and use of new technology.
- Improvements in reservoir management that lead to reductions in steam-to-oil ratios or EOR intensity, resulting in energy and GHG savings.
- Credit for solar PV exports to the grid to offset own-use power at night.
- Use of energy storage to enable greater onsite renewable energy penetration. (WSPA2_61-20)

Comment: As with refinery investment credit projects, we believe there are several additional technology and efficiency options that should be added to the innovative crude section, including:

- Improvements in efficiency, including process efficiency (using advanced control systems, digitalization, etc.), power generation efficiency, and equipment energy efficiency (through facility upgrades/retrofits and use of new technologies)
- Improvements in reservoir management that lead to reductions in steam-to-oil ratios or EOR intensity, resulting in energy and GHG savings
- Credit for solar PV exports to the grid to offset own-use power at night
- Eligibility for all renewable energy produced and used on a monthly average basis for innovative LCFS credits, including offsite contracted electricity, consistent with EV and hydrogen pathways (with same requirements for tracking) (CHEVRON1_112-23)

Agency Response: In response to this comment, staff has clarified that energy storage is an eligible innovative technology when coupled with an intermittent source of renewable electricity such as solar or wind. Staff disagrees with the recommendations to include efficiency improvement projects and improvements in reservoir management that lead to GHG savings because staff does not deem them as innovative. Finally, staff disagrees with the recommendation to credit solar PV exports to the grid to offset own-use power at night in crude applications. Staff believes that use of onsite energy storage is a better and more innovative option for excess renewable electricity and will help resolve grid balancing issues cause by intermittent renewable power sources.

In response to CHEVRON1_112-23, please see also Responses K-3.6, Book-and-Claim Accounting for Solar and Wind Electricity, and K-3.7, Net Energy Metering for Solar and Wind Electricity in this chapter.

K-3.1d. Comment: §95489(c) - Credits for Producing Crudes *and Transporting* using Innovative Methods

Pursuant to § 95489(c), the LCFS regulations currently allow for LCFS credits from innovative crude oil production and recovery. WSPA recommends expanding the existing regulations to include innovative crude oil transportation technologies. To accomplish this, we propose adding "transport (or transporter or transportation)" to the existing "Innovative Crude Production" provisions. Example changes are proposed as follows:

"§95489(c) Credits for Producing *and Transporting* Crudes using Innovative Methods. A crude oil producer*, transporter* or refinery receiving the crude may generate credits for crude oil that has been produced *or transported* using innovative methods and delivered to California refineries for processing."

"§95489(c)(1)(A) For the purpose of this section, an innovative method means crude production *or transport* using one or more of the following technologies:
…

3. …electricity must be produced and consumed onsite or be provided directly to the crude oil production *or transport* facilities from a third-party generator and not through a utility owned transmission or distribution network." (WSPA2_61-21)

Agency Response: In response to this comment, staff proposed to recognize innovative technologies used in crude oil transportation applications.

K-3.1e. *Innovative Crude Definition*

Comment: CRC is developing several project applications to employ power generation technologies under the innovative crude oil production provisions of California's Low Carbon Fuel Standard (LCFS). However, we find the definition of innovation as allowed under the current LCFS regulations limiting such that there are opportunities left unexplored.

The current regulation allows the following innovations: 1) Solar Photovoltaic, 2) Solar Thermal, 3) Wind and, 4) Carbon Sequestration. While these are useful technologies to lower the CI of crude produced in California, the list is limited and excludes several other promising routes to accomplish California's goal of reducing CI of its transportation fuels. These other routes could include geothermal energy, biogas, ocean wave energy, or some other innovative energy source or efficiency not considered under the current regulation.

CRC suggests that the existing language be broadened to include other innovative pathways such as those pathways enumerated above. CRC suggests that in addition to the existing language pertaining to CI reductions, the following language be added to §95489:

(d)(1)(A)(5) Geothermal energy,
(d)(1)(A)(6) Biogas,
(d)(1)(A)(7) Ocean wave energy, or
(d)(1)(A)(8) Other technologies or methods as approved by the Executive Officer.

The addition of this language allows the Board flexibility and discretion to use other CI reduction methods to meet California's LCFS goals. These changes will also allow California to meet directives outlined in other State laws such as the recently passed SB 1383, by providing a ready off take for economical projects outside existing power generation or natural gas vehicle markets.

CRC is committed to innovative production through construction and maintenance of integrated local energy production facilities with a highly-qualified California workforce through its project labor agreements with California's unions. We have a state-wide Project Labor Agreement with the California Building and Construction Trades Council and its 300 unions with over 450,000 members, which ensures that our facilities are built and maintained with a safe, highly-qualified workforce.

CRC believes that by providing flexibility in reduction methods will maximize the positive impact of the Innovative Crude provisions while ensuring an ample supply of crude oil for California refineries. (CRC1_35-1)

> **Agency Response:** Please see Response K-3.1a in this chapter for the recommendation to include biogas, and Response K-3.1b in this chapter for other technologies recommended for inclusion in the innovative crude provision in this comment.

K-3.2. *Solar Steam as an Innovative Method*

K-3.2a. Comment: In § 95489(c)(1)(F), we believe two additional categories should be added to represent steam quality of 45-55%, and below 45%. Some fields, driven by reservoir characteristics, operate at low steam quality and fit into those categories. Such fields should also be eligible for credits for using solar steam. (CHEVRON1_112-24)

Agency Response: In response to this comment, staff proposed to add an avoided emissions bin with a steam quality of 45-55 percent. Staff disagrees with the recommendation of adding a bin for solar steam with a quality below 45 percent. At low steam quality, the calculation of avoided emissions becomes more and more dependent on the sensible heat rather than simply the latent heat of vaporization, thereby making the calculations much more dependent on assumed values for the temperatures for the inlet water and outlet steam and water mixture. Because of this much larger variability in potential avoided emissions, staff believes that a full application including all operational data is warranted for these projects. Operators producing solar steam in this steam quality range are encouraged to apply under the solar heat generation innovative method category.

K-3.2b. **Comment:** The difference between solar steam and solar heat is not entirely clear in the regulation as written. It would be helpful to add clarity around the difference between the two. (CHEVRON1_112-25)

Agency Response: In response to this comment, staff proposed additional clarifying regulation language for solar heat: "Solar heat generation including, but not limited to, boiler water preheating and solar steam generation with a steam quality of less than 45 percent. Heat must be used onsite at the crude oil production facilities."

K-3.2c. **Multiple Comments:** ***Steam Generation Calculation for High Quality Steam***

Comment: GlassPoint believes the proposed values correspond to avoided emissions under current industry practices except for the 95% Steam Quality bin. To the end of accurately modeling avoided emissions, GlassPoint requests the coefficient associated with 95% Steam Quality be revised prior to the finalization of the rule. (GLASSPOINT1_65-4a)

Comment: *CIPA requests that the proposed 95% steam quality factor be revisited prior to final adoption to verify its alignment with standard industry practice.* (CIPA1_71-2a)

Agency Response: In response to this comment, staff proposed to revise the steam generation calculation for high quality steam in OPGEE2.0 and update the avoided emissions value for steam with a quality greater than 95 percent to align with the updated OPGEE2.0 model.

K-3.2d. **Comment:** For oil fields with two separate steam outlets, Section 95489(c)(4)(E) will need to be adjusted to account for the circumstance where only one component of the field is connected to the solar steam. (GLASSPOINT1_65-10)

Agency Response: Staff disagrees with the comment. Section 95489(c)(4)(E) provides detailed reporting requirements necessary to calculate the amount of credits to be awarded to the solar steam project. As long as all data necessary

for credit calculation is reported consistently using the same field-level boundaries, then the credit calculation should be accurate.

K-3.3. *Environmental Attribute*

Comment: The new provision 95489(c)(1)(G) is overly broad and should be limited to "greenhouse gas related environmental attributes". (GLASSPOINT1_65-9)

> **Agency Response:** Staff disagrees with this recommendation as the definition of "environmental attribute" in section 95481 specifically limits the context of this phrase under the LCFS to greenhouse gas emission reductions and, therefore, the stakeholder's suggested revision is not necessary.

K-3.4. *Credit Generation and Third-Party Eligibility to Generate Credits*

Comment: The stability of the credit generating stream for a solar steam project is a critical requirement for project investors. GlassPoint requests that the regulations include a provision that when a project is approved, its LCFS credit values per barrel of steam or per kWh of electricity are fixed for the project life. (GLASSPOINT1_65-11)

> **Agency Response:** Although staff understands the argument made in this comment, the LCFS as currently structured does not guarantee credit value for a fixed time for any fuel pathway or emission reduction project. This would be a major change to the program, which staff believes should involve engagement of a wide variety of stakeholders as part of a lengthier workshop process. However, staff has proposed clarifying regulation language stating that the avoided emissions values for solar steam projects are to be calculated using the OPGEE model assuming displacement of steam produced using a once-through-steam-generator. This additional language should provide some level of assurance by specifying exactly how the avoided emissions values are calculated.

K-3.5. *Credit Reporting and Verification Requirements*

Comment: Section 95489(c)(4)(C) – Recordkeeping and Reporting requires documentation of BOTH of the following: that the innovative crude was supplied to California refineries, and the volume of innovative crude supplied to each refinery. CIPA supports the first requirement. It makes sense to ensure that the crude for which credits are supplied, actually comes to California. It is the second part of that requirement is problematic and unnecessary for in-state producers. It problematic as the volume of crude produced is already supplied to other state agencies in a manner that has been established over the years. Separating the data out by one particular technology, or by one particular customer is a real issue. But due to the structure of the calculation, this information is unnecessary as the V_{innov} and $V_{crudeproduced}$ are identical terms, for in-state production, and therefore cancel each other out. This nullifies the need for the volume of crude produced to be collected and verified under this program. (CIPA1_71-6)

Agency Response: In response to this comment, staff has proposed that for crude oil produced in California, the following should be submitted: documentation showing the innovative crude was supplied to a California refinery(ies), the total volume (barrels) of innovative crude supplied to California refineries, and the total volume (barrels) of innovative crude exported from California. This documentation is sufficient to prove that the innovative crude was supplied to California refineries and not exported.

K-3.6. Multiple Comments: *Book-and-Claim Accounting for Solar and Wind Electricity*

Comment: In § 95488.8(i), ARB proposes a method whereby a pathway applicant may use book-and-claim accounting to allocate low-CI electricity production to their electricity or hydrogen pathway, provided certain conditions are met. We propose a similar provision would benefit the program under § 95489(c), Credits for Producing Crudes using Innovative Methods and § 95489(e), Refinery Investment Credit Pilot Program.

The program currently allows crude production facilities and refineries to generate credits for renewable electricity produced and consumed by the facility. In some circumstances, it may make operational sense to direct renewable electricity produced on site to the grid and consume electricity from the grid. WSPA proposes that ARB incorporate the book-and-claim accounting option for renewable electricity in the rules for innovative crude credits and for refinery investment credits. (WSPA2_61-19)

Comment: In § 95488.8(i), staff proposes a method whereby a pathway applicant may use book-and-claim accounting to allocate low-CI electricity production to their electricity or hydrogen pathway, provided certain conditions are met. We propose a similar provision would benefit the program under § 95489(c), Credits for Producing Crudes using Innovative Methods. The program currently allows crude production facilities to generate credits for renewable electricity produced and consumed by the facility. In some circumstances, it may make operational sense to direct renewable electricity produced on site to the grid and consume electricity from the grid. Chevron proposes that CARB incorporate the book-and-claim accounting option for renewable electricity in the rules for innovative crude credits. (CHEVRON1_112-22)

Comment: Likewise, the prohibition against receiving LCFS credits for renewable electricity procured from an off-site project and delivered to serve on-site refinery or crude production loads should be eliminated. There is no meaningful climate benefit distinction between renewable electricity generated from an on-site system and that from an off-site system. The important point is fostering and fulfilling the increased private demand for renewable energy being created by the refinery or crude production operation. This would also align with the staff proposal "to allow renewable power generated in the same balancing authority as the ZEV load to be used in EV charging and H2 production."[1]

1 CARB *NOTICE OF PUBLIC HEARING TO CONSIDER PROPOSED AMENDMENTS TO THE LOW CARBON FUEL STANDARD REGULATION AND TO THE REGULATION ON COMERCIALIZATION OF ALTERNATIVE DIESEL FUELS*, Page 7

(SUNPOWER1_70-2)

Comment: Likewise, the prohibition against receiving LCFS credits for renewable electricity procured from an off-site project and delivered to serve on-site refinery or crude production loads should be eliminated. There is no meaningful climate benefit distinction between renewable electricity generated from an on-site system and that from an off-site system. This would also align with the staff proposal "to allow renewable power generated in the same balancing authority as the ZEV load to be used in EV charging and H2 production." (SEIA1_119-6)

> **Agency Response:** Electric Vehicle Charging and Hydrogen Refueling are substantially different processes compared to conventional fuel production and biofuel production processes. Electric Vehicle charging often occurs in urban areas with limited land-area footprints for on-site renewable generation. Allowing off-site renewable electricity generation to be contracted for use at large-scale chemical production facilities is not comparable to EV charging given that industrial chemical plants are often located away from urban areas and have substantially larger land-use footprints, compared to charging stations, which makes on-site integration of low-carbon electricity viable for these chemical pathways. There are additional concerns affiliated with overlapping incentive programs that already exist to promote the adoption of renewable electricity use at these large facilities. Given the land area available to larger production facilities, the LCFS will continue to require behind-the-meter renewable electricity demonstration for most fuel pathways to assure that the renewable load is correctly being matched and adequately integrated into the production facility's process for fuel production.
>
> Similarly, staff disagrees with the recommendation to allow book-and-claim accounting for demonstrating the use of renewable electricity under the innovative crude provision. Under staff's proposal, book-and-claim accounting can only be used for allocating low-CI electricity to electric vehicle charging or hydrogen production using electrolysis; it would not be allowed for other alternative fuel pathways, refinery investment credit, or the innovative crude provision. Staff is allowing book-and-claim accounting for electric vehicle charging and for hydrogen production partly because these facilities are most often located in dense urban environments with insufficient footprint to support renewable electricity production. The same cannot often be said for crude oil production. Moreover, the intent of the provision is to provide incentive for innovative technologies used to reduce emissions at oil fields. Staff believes that renewable electricity that is directly supplied to the oil field, especially when coupled with onsite storage, is in line with the innovative intent of the provision.

K-3.7. Multiple Comments: *Net Energy Metering for Solar and Wind Electricity*

Comment: However, these rules are unjustifiably limiting in how renewable generation can qualify. For example, for solar and wind electricity projects, § 95489(c)(1)(A) indicates that electricity from such projects "must be produced and consumed onsite" in order to qualify for credits. Established state policy on net energy metering (NEM) affords a customer the ability to size an on-site renewable generator to meet up to

100% of the customer's annual electricity load. Whatever electricity is not utilized instantaneously behind-the-meter can be exported to the grid and utilized by the customer's operation at another time. We recommend that this regulation be revised (or clarified) to allow *the total output* of an on-site renewable generation system to qualify for LCFS credits. (SUNPOWER1_70-1a)

Comment: However, we believe that the LCFS regulation should be consistent between calculations for innovative crude and other fuel pathways. Specifically for fuel pathways, there is an enumerated list of criteria defining what it means for renewable electricity to be "directly consumed in the production process." For renewable electricity used to produce innovative crude, the language "consumed for crude oil production" is used but no list of specific requirements is given to determine if the requirement has been met.

In the comment below we have highlighted the inconsistences and propose consistent language for the future regulation. EnergyField submits the following comment for consideration:

As proposed section §95489(c)(4)(D) states

For solar or wind electricity projects, the following additional recordkeeping and reporting will be required:

1. Metered data on solar or wind electricity consumed for crude oil production at the oil field during the quarter (kWh);

2. Metered data on total electricity consumed for crude oil production at the oil field during the quarter (kWh); and

3. An attestation letter stating that all solar or wind electricity was supplied directly for crude oil production at the oil field and that the solar or wind electricity reported for generating LCFS credit did not produce renewable energy certificates or other renewable attributes recognized or credited by any other jurisdiction or regulatory program.

In the context of the complete set of proposed amendments, it is unclear what "consumed for crude oil production" or "supplied directly for crude oil production" means and what accounting methods may be used to establish such consumption/supply.

In section §95488.8(h) for renewable or low-CI process energy, the as-proposed regulation clarifies what it means for renewable electricity to be "directly consumed in the production process." Specifically, the as-proposed regulation states:

Renewable electricity must be supplied from generation equipment under the control of the pathway applicant. Such renewable electricity must be able to demonstrate:

(A) Any renewable electricity certificates or other environmental attributes associated with the energy are not produced, or are retired and not claimed under any other program with the exception of the federal RFS.

(B) The generation equipment is directly connected through a dedicated line to a facility such that the generation and the load are both physically located on the customer side of the utility meter. The generation source may be grid - tied, but a dedicated connection must exist between the source and load.

(C) The facility's load is sufficient to match the amount of renewable electricity claimed using a monthly balancing period.

In light of the above, EnergyField proposes that section §95489(c)(4)(D) be re-written to state:

For solar or wind electricity projects, the following additional recordkeeping and reporting will be required:

1. Metered data on solar or wind electricity consumed for crude oil production at the oil field <u>for each month</u> during the quarter (kWh);

2. Metered data on total electricity consumed for crude oil production at the oil field <u>for each month</u> during the quarter (kWh); and

3. An attestation letter stating that all solar or wind electricity ~~was supplied directly for~~ <u>consumed in the production process of</u> crude oil <u>as described in (A), (B), and (C) below</u> ~~production at the oil field and that the solar or wind electricity reported for generating LCFS credit did not produce renewable energy certificates or other renewable attributes recognized or credited by any other jurisdiction or regulatory program.~~

> **<u>(A) Any renewable electricity certificates or other environmental attributes associated with the solar or wind electricity are not produced, or are retired and not claimed under any other program.</u>**
>
> **<u>(B) The generation equipment is directly connected through a dedicated line to a facility such that the generation and the load are both physically located on the customer side of the utility meter. The generation source may be grid - tied, but a dedicated connection must exist between the source and load.</u>**
>
> **<u>(C) The crude oil production facility's load is sufficient to match the amount of renewable electricity claimed using a monthly balancing period.</u>**

We believe that similar and consistent language should be use throughout the entire regulation whenever a specific source of energy or feedstock is required to be "consumed on site" or "consumed in the production process" of a particular pathway or project. (EF1_3-2)

Comment: The LCFS regulations allow for program participants to receive LCFS credits for utilizing renewable electricity in both conventional fuel refinery operations and crude production. This is an important policy to further drive private adoption of renewable energy to help meet the state's climate goals.

However, these rules are unjustifiably limiting in how renewable generation can qualify. For example, for solar and wind electricity projects, § 95489(c)(1)(A) indicates that electricity from such projects "must be produced and consumed onsite" in order to qualify for credits. Established state policy on net energy metering (NEM) affords a customer the ability to size an on-site renewable generator to meet up to 100% of the customer's annual electricity load. Whatever electricity is not utilized instantaneously behind-the-meter can be exported to the grid and utilized by the customer's operation at another time. We recommend that this regulation be revised (or clarified) to allow the total output of an on-site renewable generation system to qualify for LCFS credits. (SEIA1_119-5)

> **Agency Response:** The LCFS is a program specifically intended to decarbonize transportation fuel. Renewable electricity connected to the grid that is in excess of the electricity consumed, on-site, to produce transportation fuel would go toward alternative applications. Renewable Portfolio Standards in California and other States already create incentives for renewable electricity supplied to the grid. At this time, there is little reason to provide offsets relative to conventional transportation fuels for renewable electricity generation produced on-site that is in excess of the electricity required at a process level to produce the transportation fuel at that location.
>
> Staff disagrees with the recommendations that net energy metering or monthly balancing of electricity under the innovative crude provision is appropriate. Rather than providing incentive for overproduction of renewable electricity and export to the grid under a net energy metering contract, staff believes it is better to promote a more innovative solution using onsite storage of excess renewable electricity that is then used when the intermittent electricity source is not producing.

L. Refinery-Related Provisions

L-1. Multiple Comments: *Support for Proposed Revisions to the Refinery Investment Credit Pilot Program and Renewable Hydrogen Refinery Credit Program*

Comment: The RNG Coalition SUPPORTS the proposed changes to the Refinery Investment Credit Pilot Program (RICPP) to focus the provision on innovative changes at refineries. Specifically, we support the ability of refiners to generate credits for fossil fuel substitution by renewable fuels, including RNG, for process energy. The benefit of fossil fuel substitution is that it takes advantage of existing refinery equipment and involves no process or capital changes while still providing lifecycle carbon-intensity reductions. (RNGC1_16-2)

Comment: WSPA supports a well-designed RICP to provide the opportunity to reduce the carbon intensity (CI) of fuels produced in refineries in California. Such a program can incent both short-term improvements that will often provide criteria pollutant co-benefit reductions, and in the longer-term incent more transformational technologies that can contribute meaningfully for California meeting its climate goals. (WSPA1_21-1)

Comment: But we're going to face some challenges with this program going forward, and so we have three concepts that we think would add value. Those are the Refinery Investment Credit Program. We really support a well-designed program in this area. It cannot only incent short-term improvements, but also longer-term, incent more trans -- transformational technologies to meet these goals. (WSPA4_T48-3)

Comment: Additionally, Andeavor would like to thank CARB for taking the steps in the proposed regulation to clarify the Refinery Investment Credit Pilot Program (RICP). The changes allow for refineries to evaluate and justify capital expenditures for projects to reduce the CI of fuels produced. Andeavor specifically endorses WSPA's position on this topic. (ANDEAVOR1_67-7)

Comment: First, thank you for the work that Sam and his staff have done to clarify large portions of this regulation; specifically, enhancing the refinery investment credit program language. Directionally, the proposed changes will allow for Andeavor to better evaluate and value process improvement projects aimed at reducing the CI of the fuels we produce. (ANDEAVOR2_T10-1)

Comment: Chevron appreciates the progress that has been made on the Refinery Investment Credit Program (RICP) in the proposed amendments. We support the change to the qualification date from permitted after January 1, 2016 to completed after that date. This recognizes the fact that considerable time can pass between permitting and completion and that a permit is not necessarily a guarantee that a project will be fully executed. Qualification for LCFS credits should occur upon achieving a decisive element in a permitted project, that is, full completion. (CHEVRON1_112-9)

Comment: We support the inclusion of a process-improvement project category under § 95489 to qualify for RICP credits. Just as innovative technologies like solar electricity and renewable process fuels reduce GHG emissions, so can any non-routine project that also reduces the emissions associated with producing fuel and should be recognized on equal terms. Given that the carbon intensity values for CARBOB and diesel fuel are fixed, this is the most direct way for a refinery to contribute to reducing emissions related to those petroleum products. (CHEVRON1_112-11)

Comment: Kern is generally supportive of the RICPP and appreciates ARB's proposal to shift the threshold for determining eligibility to a one percent reduction of on-site refinery level GHG emissions. Kern is encouraged by the proposal to account for GHG emissions at the process unit/project boundary level, but cautiously reiterates the need for flexibility in doing so.

…

Kern is encouraged that application of a one percent threshold couples the amount of reduction to a refinery specific ratable parameter. This approach effectively achieves ARB's goal of reducing GHG emissions but avoids sizing out smaller refineries from the RICPP – something other thresholds considered would have done. Furthermore, ARB's proposal maintains the threshold at a degree which balances the incentive for executing a project with a small refiner's financial ability to make qualifying investments. (KERN1_115-7)

Comment: Requiring the quantification of emissions reductions at the project boundary level will provide for appropriate data comparisons while allowing for the necessary accounting flexibility. Refineries utilize a variety of data sources and methodologies to quantify and account for the material inputs, necessary utilities, and product outputs. No two refineries are alike, and no two refineries employ identical means to account for these parameters. The use of consistent measurement approaches across the pre- and post-project estimation methodologies will ensure integrity in the determination of emissions reduction achieved. (KERN1_115-7b)

Comment: The refinery investment credit program, under LCFS offers the opportunity in the nearer term to enable investments to reduce the CI fuels needed today. (SHELL1_T50-1)

Comment: 8. NRDC supports the inclusion of provisions that will result in direct emission reductions from refineries and crude oil facilities

Since 2012, NRDC has supported CARB's efforts to establish credits for GHG emission reductions from refinery improvement and crude oil emission reduction projects, and we have at times worked and joined together with labor organizations under Blue-Green Alliance. Credits for refinery improvements represent a significant opportunity to spur additional investments that improve the environmental performance of refineries and that create secure refinery jobs, while reducing the carbon-intensity of transportation fuels and fostering additional benefits such as reductions in criteria pollution. To that

end, we asked ARB in 2015 to help ensure that the projects represent actual capital investments to reduce carbon emissions (as opposed to simply shutting down units), creating net reductions in carbon-intensity across the refinery, and be limited to projects undertaken to help comply with the standards beyond business-as-usual, and to demonstrate the projects would meet local restrictions around air quality and criteria emissions.[5] We thank ARB for working diligently to add provisions to help ensure we can achieve multiple benefits. At the same time, we urge ARB to continue to require from parties that the reductions are real and verifiable, consistent with maintain the integrity of the program.

[5] NRDC and Blue Green Alliance (February 17, 2015). Letter to the Board.

(NRDC1_81-17)

Comment: Carbon Creek commends the California Air Resources Board's ("ARB") dedication to incentivizing innovative practices that reduce greenhouse gas emissions ("GHGs") at petroleum refineries in California. (CCE1_32-1)

Comment: PG&E supports CARB's proposal to remove limiting restrictions on refiners' ability to generate and trade credits from innovative refinery investment projects and renewable hydrogen projects. For example, the proposed changes to the Refinery Investment Credit Pilot Program and the Renewable Hydrogen Refinery Credit Pilot Program would support refiners' ability to generate credits by substituting RNG for fossil natural gas. RNG can be used in existing refinery equipment without any process changes while providing CI reductions. PG&E encourages CARB to explore additional credit generation options like these to the fullest extent to support the ambitious LCFS targets. (PGE1_120-25)

Comment: The LCFS is even more important over the coming decade because it represents one of the only measures by which the state can support emissions reductions in the refinery sector, which accounts for over 45% of industrial emissions or almost 11% of the state total. AB 398 (Chapter 135, Statutes of 2017) authorizes the extension of several key carbon pollution reduction policies, but categorically excludes oil production and refining from direct regulation. It also extends highly preferential treatment under the Industrial Assistance provisions of the Cap and Trade program. The LCFS, through existing and proposed provisions relating to refinery investments, carbon capture and sequestration, innovative crude production and renewable hydrogen, can drive reductions in this sector. Achieving 40% reductions in carbon pollution by 2030 will be much more difficult if the refining sector does not reduce its emissions to keep pace with the economy as a whole. The LCFS is now the best tool at California's disposal to ensure that the refinery sector makes the investments to do its part. (NEXTGEN1_124-3b)

Comment: Refinery renewable hydrogen offers a large scale opportunity to embed renewable content in California's gasoline and diesel fuel, leveraging today's refinery, fueling, and vehicle infrastructure to make lower GHG emissions fuels. We commend and support CARB's proposal to remove the limits on the generation of LCFS credits using refinery renewable hydrogen, to remove the minimum threshold for volume utilized, and to simplify the credit generation formulae. We believe there is tremendous

potential for the utilization of RNG to make renewable hydrogen that is ultimately incorporated in California's gasoline and diesel fuel. We are actively working with several California refiners to bring this new pathway to market; however largescale implementation will be impaired until EPA accepts a renewable hydrogen content pathway for D3 RIN generation. Iogen looks forward to working with CARB to realize widespread implementation of refinery renewable hydrogen in California. (AJWIOGEN1_17-2)

> **Agency Response:** Staff appreciates the above comments in support of proposed changes to refinery-related provisions. Staff believes that the proposed Refinery Investment Credit Pilot Program (RICPP) and Renewable Hydrogen Refinery Credit Program (RHRCP) flexibly encourage GHG reductions projects at refineries, which range from process improvements to innovative projects such as the use of renewable process energy inputs and carbon capture and sequestration. Staff also believes the proposed credit calculation methods for the RICPP and RHRCP are simple and robust, and ensure that GHG reductions are real and verifiable while maintaining the integrity of the programs.

L-2. *Refinery Investment Credits Pilot Program*

L-2.1. Multiple Comments: *Limit on Credit Generation*

Comment: The industry recognizes the ARB's desire is for the LCFS to incent a variety of types of CI reductions, and must ensure that individual programs in the LCFS are both manageable and would not overwhelm the program in a way to compromise its other objectives. To help understand what a well-designed RICP would need to consider, WSPA commissioned a survey of its member companies to help frame the potential magnitude of utilization of this program. The blinded results were consolidated and are presented in Tables 1-3. **These tables represent industry aspirations; not all of these projects will ultimately come to fruition, but provides a reasonable basis for what the ARB could consider that the program may incentivize.**

Table 1 – Anticipated Total Count of Projects by Year

	Year Submitted (or Projected to be Submitted) to ARB for Approval							
GHG Emission Reduction	2019	2020	2021	2022	2023	2024	2025	>2025
10,000-19,999 MT	3	2	0	3	0	1	1	1
20,000-39,999 MT	4	1	2	0	1	0	0	0
40,000-99,999 MT	2	0	1	1	0	0	0	1
≥100,000 MT	2	1	0	1	0	0	0	0

Table 2 – Total GHG Emission Reduction Project Credits
Anticipated Average Credits for Years of Application

	Year Submitted (or Projected to be Submitted) to ARB for Approval							
GHG Emission Reduction	2019	2020	2021	2022	2023	2024	2025	>2025
10,000-19,999 MT	45,000	30,000	0	45,000	0	15,000	15,000	15,000
20,000-39,999 MT	120,000	30,000	60,000	0	30,000	0	0	0
40,000-99,999 MT	140,000	0	70,000	70,000	0	0	0	70,000
≥100,000 MT	700,000	350,000	0	350,000	0	0	0	0

Table 3 – Total GHG Emissions Reduction Project Credits
Anticipated Average Credits for Year of Implementation

	Year (or Anticipated Year) of Project Implementation									
GHG Emission Reduction	2019	2020	2021	2022	2023	2024	2025	2026	2027	≥2028
10,000-19,999 MT	22,500	22,500	0	30,000	0	45,000	0	15,000	15,000	15,000
20,000-39,999 MT	60,000	60,000	0	30,000	60,000	0	30,000	0	0	0
40,000-99,999 MT	70,000	70,000	0	0	70,000	70,000	0	0	0	70,000
≥100,000 MT	350,000	350,000	0	0	350,000	0	350,000	0	0	0

(WSPA1_21-2)

Comment: The survey information further suggests that refineries in California ultimately could, by way of efficiency improvement projects, deliver about 10% of the total CI improvements that would be projected to be required by the ARB's "low demand" case in its illustrative compliance calculator on the LCFS website. Given this, WSPA concurs that setting aside as much at 20% of program credits for these types of projects is unwarranted and would advocate that a 10% limit for these types of projects would be reasonable. Given that the delivery of such projects will vary by facility, it will be important to confirm tradability of such allowances within the LCFS market. That the tradability restriction language has been lifted seems to indicate this is the ARB's intent, but WSPA would appreciate the inclusion of language that would confirm trading of credits derived by the RICP is permitted.

…

§95489. Provisions for Petroleum-Based Fuels
(e) Refinery Investment Credit Program
(1) General Requirements

ARB Proposed Language

(H) Credits generated pursuant to section 95489(e)(1)(E)(5) may not be used to meet more than **5** percent of any entity's annual compliance obligation. The Executive Officer will exclude incremental deficits incurred pursuant to section 95489(b) when assessing this **5** percent limitation.

Alternative Language

(H) Credits generated pursuant to section 95489(e)(1)(E)(5) may not be used to meet more than **10** percent of any entity's annual compliance obligation. The Executive Officer will exclude incremental deficits incurred pursuant to section 95489(b) when assessing this **10** percent limitation. (WSPA1_21-4)

Comment: Further, Kern urges ARB to eliminate the limitations on refinery process improvement projects imposed by Section 95489(e)(1)(H) and (I). Capping the use of credits generated from process improvements to meet no more than five percent of a facility's annual compliance obligation serves no benefit to LCFS and places unnecessary restrictions on a regulated party. Credits generated under the RICPP provision will have undergone the rigorous requirements of a third-party verification. All credits generated should be of equal value and utilized without restriction. (KERN1_115-7d)

Comment: The proposed revisions to the Refinery Investment Credit Program provide greater flexibility and credit generation potential for renewable fuel and Carbon Capture and Sequestration (CCS) projects than for industrial process improvement projects, despite the fact that all projects result in reduced greenhouse gas emissions. Process improvement investment project credits are limited to a maximum of 5% of an entity's annual compliance obligation and expire January 1, 2025. These restrictions will mute the economic benefit of any process improvement project being considered. Projects involving carbon capture and sequestration, use of renewable or low CI electricity or lower CI process energy and replacement of high carbon fossil energy input with lower carbon grid electricity are not subject to the same restrictions as process improvement projects. There is no evident basis for this arbitrary limitation on the credit generation potential of process improvement projects, and such a limitation would frustrate the goals of the LCFS program. (VALERO1_69b-3)

Comment: Additionally, we request that you consider the comments submitted by WSPA on this subject, as we believe they further enhance the provision. (ANDEAVOR2_T10-2)

Comment: §95489. Provisions for Petroleum-Based Fuels
(e) Refinery Investment Credit Program
(1) General Requirements

ARB Proposed Language

~~(F) Credits created pursuant to Section 95489(g) may not be sold or transferred to any other party.~~

Alternative Language

(F) Credits created pursuant to Section 95489(f) may be sold or transferred to any other party. (WSPA1_21-17)

Agency Response: Staff appreciates the submission of a survey commissioned by WSPA as part of the 45-day comments. The survey shows the potential number and type of the process improvement projects that could be incentivized under the RICPP. Staff agrees with stakeholder comments that the proposed five percent threshold could be unduly limiting. Therefore, as part of the 15-day changes staff proposed that credits generated from process improvement projects may not exceed 10 percent of any entity's annual compliance obligation. Staff disagrees with the recommendation in some of the comments that credit generation from process improvement projects be unlimited, similar to credits from more innovative projects such as carbon capture and sequestration, electrification of equipment, and use of low-CI electricity and process energy. It is staff's intent to provide greater incentive for these innovative projects that are necessary for long-term decarbonization of the refining industry.

In response to WSPA1_21-4, the proposed RICP Program does not put tradability restrictions on credits generated under the RICP Program. WSPA has acknowledged this in its comment letter. Therefore, staff does not agree that additional clarifying language is necessary.

L-2.2. Multiple Comments: ***GHG Reduction Threshold for Eligibility***

Comment: The ARB's draft rulemaking language that provides for a project qualification via a GHG emission reduction threshold is an important improvement that we support. The survey results help inform the optimum level to set such a threshold and strongly suggest that a 10,000 MT threshold for projects quantified by direct emission reductions would be appropriate. Even at this threshold, the survey results would indicate that there would likely only be 2-3 projects per year after an initial tranche of 10-12 pending projects are brought forward when a workable RICP is provided in rulemaking.

…

Retaining a 1% threshold as a secondary approach could still be of benefit to smaller refiners and provide a pathway for additional projects, and thus should be retained as an alternative threshold.

…

§ 95489. Provisions for Petroleum-Based Fuels
(e) Refinery Investment Credit Program
(1) General Requirements

ARB Proposed Language

(C) The refinery investment credit project must achieve a carbon intensity reduction equivalent to at least 1 percent of pre-project on-site refinery-wide greenhouse gas emissions (baseline) in metric tons per year.

Alternative Language

(C) The refinery investment credit project must generate a reduction of at least 10 kt/yr of CO2e or 1% of pre-project on-site refinery-wide greenhouse gas emissions (baseline) in metric tons per year, whichever is lower. Further, for any refinery investment credit project including projects involving hydrogen plant(s)or cogeneration unit(s), the baseline calculation of the total applicable refinery emissions shall exclude the emissions from these facilities consistent with their being reported separately under MRR. (WSPA1_21-3)

Comment: We are concerned about the GHG reduction thresholds proposed in the amendments. A 1% threshold can be achievable for a small-scale refinery executing a project that reduces GHGs, but this will be a much higher threshold for large refineries. We believe that the choice between an absolute threshold and a lower percentage threshold will be more equitable. We concur with the WSPA proposal to set the threshold at 10,000 MT CO2e per year or 0.5% of pre-project refinery-wide emissions, whichever is lower. (CHEVRON1_112-10)

> **Agency Response:** Staff agrees with stakeholder comments recommending flexibility in the GHG threshold for projects under the RICPP. In response to these comments, staff proposed to include a 10,000 MT threshold in addition to the 1 percent GHG reduction threshold as part of the 15-day changes.
>
> In response to WSPA1_21-3, due to the proposed flexibility (1 percent or 10,000 MT CO_2 GHG reductions/year), there is no need to include the above statement proposed by WSPA because this statement is relevant only if CARB had elected to retain the 1 percent threshold only.

L-2.3. Multiple Comments: ***Crediting Period for Process Improvement Projects***

Comment: What will be imperative for a successful RICP is that refineries have confidence in the time window during which projects can earn credits. Attempting to define the credit generation window based on a calendar is problematic, as projects will develop over time, and will have significantly variable durations for their development, permitting and implementation. A program that would provide a fixed year of credits for approved projects upon start-up will effectively address this concern. Given that the major types of investments that refineries make are typically designed to last 25 years or more and it is not uncommon for regulatory agencies to recognize project benefits for the life of the project, this section of the regulation should be considerate of the long-time horizons for such investments. To balance the need that ARB has expressed to drive more aspirational technologies longer-term, WSPA would recommend that a 15-year window be provided for projects that are approved under the RICP. The longest credit generation window that can be provided will incent the maximum number of projects, as the value of these credits would be factored into every project's economic evaluation. More projects equates to more GHG emission reductions, more co-benefit pollution reductions, and more jobs and investment in California.

…

§95489. Provisions for Petroleum-Based Fuels
(e) Refinery Investment Credit Program
(1) General Requirements

ARB Proposed Language

(I) Credits may not be generated pursuant to section 95489(e)(1)(E)(5) after January 1, 2025.

Alternative Language

(I) Credits would be valid for a period of 15 years after start-up of an approved RICP project. (WSPA1_21-5)

Comment: Staff discussion in the ISOR justifies a sunset of the process improvement credit by 2025 as a means to encourage more innovative reductions at refineries. Kern disagrees with this narrow vision of how GHG emissions reductions should be achieved, and emphasizes the need to incent long-term reduction projects, whether perceived as innovative or not. (KERN1_115-7e)

Comment: The proposed revisions to the Refinery Investment Credit Program provide greater flexibility and credit generation potential for renewable fuel and Carbon Capture and Sequestration (CCS) projects than for industrial process improvement projects, despite the fact that all projects result in reduced greenhouse gas emissions. Process improvement investment project credits are limited to a maximum of 5% of an entity's annual compliance obligation and expire January 1, 2025. These restrictions will mute the economic benefit of any process improvement project being considered. Projects involving carbon capture and sequestration, use of renewable or low CI electricity or lower CI process energy and replacement of high carbon fossil energy input with lower carbon grid electricity are not subject to the same restrictions as process improvement projects. There is no evident basis for this arbitrary limitation on the credit generation potential of process improvement projects, and such a limitation would frustrate the goals of the LCFS program. (VALERO1_69b-3)

> **Agency Response:** Staff agrees with stakeholder comments that ending credit generation for process improvement projects in 2025 would be unduly restrictive. In response to these comments and considering the long lead-times involved for refinery projects in planning, permitting and implementation and the need for credit certainty, staff proposed to allow credit generation for 15 years after the approval of project. However, staff proposes maintaining the requirement that the proposed project be implemented by 2025. This would provide an adequate crediting period and policy certainty for near-term projects to be factored into project's economic evaluation while signaling movement towards more innovative projects in the long-term.

L-2.4. ***Credit Calculation Methods***

L-2.4a. **Comment:** In § 95489(e)(2)(B)(2) and § 95489(f)(2)(A), it is not clear what the term $Volume^{Total}$ is intended to include that is different from $Volume^{XD}$ in the numerator. WSPA requests further clarification. (WSPA1_21-6)

> **Agency Response:** The purpose of equations in section 95489(e)(2)(B)(2) and section 95489(f)(2)(A) is to prorate the amounts of credits if not all of gasoline/gasoline blendstocks and diesel produced at the refinery is supplied or offered for sale in California. $Volume^{Total}$ refers to the total volume of gasoline/gasoline blendstocks and diesel produced at the refinery, whereas $Volume^{XD}$ refers to the volume of gasoline/gasoline blendstocks and diesel in gallons per year produced at the refinery and sold, supplied, or offered for sale in California by the refinery involved in the Refinery Investment Credit Program. As part of the 15-day changes, staff has proposed revised language to clarify the meanings of $Volume^{XD}$ and $Volume^{Total}$.

L-2.4b. **Comment:** With respect to § 95489(e) Refinery Investment Credit Pilot Program and § 95489(f) Renewable Hydrogen Refinery Credit Program, BP would strongly recommend that CARB reconsider the definition language applied in the Calculation of Credits sections for $Volume^{XD}$ and $Volume^{Total}$. (Sections 95489(e)(2)(B) and 95489(f)((2)(A)). These definitions require the refinery involved in those respective programs to sell, supply, or offer CARBOB or diesel in California. However, the limitation in that definition to the specific refinery involved in the program also needing to sell, supply, or offer the fuel into the state fails to account for the numerous fuel exchange agreements that petroleum companies, like BP, have with other petroleum companies in West Coast Petroleum Administration for Defense District 5 (PADD 5). Under those agreements oil companies exchange quantities of fuel with other fuel producers located closer to the intended market for the fuel, thereby reducing transportation costs and GHG emissions.

It is BP's view that the way the current language is written could lead to unintended consequences for the program. At one end of the spectrum it could lead to unnecessary product transport for the refineries involved, resulting in increased GHG emissions being generated through attracting physical imports of fuels into the state that may otherwise have been part of a reciprocal exchange arrangement within the PADD. At the other end of the spectrum it may result in providing insufficient incentive for refineries to participate in the program to drive the intended GHG reductions at the refinery.

In keeping with the introductory language in the sections above which states, "Any such credits must be based on fuel volumes sold, supplied, or offered for sale in California as set forth below", we believe that this should be specific to a given entity's obligated volume and that the following definitions apply:

- $Volume^{XD}$ should reference "…by the regulated entity" and not "…by the refinery". This is in recognition that in order to simplify PADD level logistics (such as

through exchange type arrangements), it can often be the case that not all fuels sold by a regulated entity in California may necessarily originate from the refinery generating credits under these two refinery credit programs (RCP). Additionally, it is possible that not all sales by an obligated party from a RCP refinery carry that entity's obligation.

- For $Volume^{Total}$ as defined in proposed Sections 95489(e)(2)(B) and 95489(f)((2)(A) it is appropriate to reference total volume of "gasoline" as opposed to total volume of "CARBOB". This is based on the possibility that not all gasoline produced at a regulated entity's refinery is necessarily a CARBOB, as it is possible that not all gasoline production from a regulated entity's refinery will be for sale in California.

BP also has comments on §-95490 Provisions for Fuels Produced Using Carbon Capture and Sequestration similar to those provided above. Under the paragraph General Requirements (3), the program requires that credits must be prorated based on the volumes delivered to California. For the same reasons as stated above and in order to encourage participation in the RCP being made available, BP would strongly recommend that credits be prorated to the regulated entity's obligated volumes in California and not be limited to physical deliveries to the state.

Ultimately regulated entities with refineries are looking to refinery generated credits to facilitate the reduction of the GHG footprint at their facilities and use those credits to satisfy their obligated volumes carried in the state of California. If, for the purpose of generating RCP credits, CARB only permits the generation of credits for physical molecules leaving the refinery and being sold over a California rack, it could either undermine the incentive to participate in the RCP to deliver the changes, or it could change trade flows within the PADD by attracting more physical imports into California.

BP also believes that the regulation should be clear in stating that the volume generating the entity's obligation (pro-rated if entity has more than one refinery with California sales) should be the $Volume^{XD}$ used in the RCP / CCS credit calculations. (BP1_125-1)

> **Agency Response:** Staff disagrees with the first part of this comment. Since petroleum fuels produced in a refinery but not sold in California do not carry an obligation under the LCFS, it is appropriate that the credits earned through refinery-related provisions should be limited to the volume of petroleum fuels sold/used in California. Hence, staff believes that the current definition for $Volume^{XD}$ is appropriate.
>
> In response to the second part of this comment, staff has proposed revising the language by replacing "CARBOB" with "gasoline/gasoline blendstocks."

L-2.4c. **Comment:** Global Warming Potential (GWP) values will change from time to time which can impact the emission calculations. It is unclear in the regulatory language if those changes will be credited or debited to a project at the corresponding

number of credits related to the change or will the project be grandfathered in. WSPA requests that the regulatory language provide direction in such cases. (WSPA1_21-12)

> **Agency Response:** Staff is aware that Global Warming Potential (GWP) values may change from time to time which can influence the amounts of credits generated. Similar to GREET model updates which may also impact carbon intensity scores, GWP value updates would be part of routine GREET model updates and apply to both the baseline and project emissions. As a result, staff does not believe that a grandfathering provision is necessary.

L-2.4d. Comment: *NextGen Supports the Including Credit Generation Pathways for Co-Processing of Biomass Feedstock and Emissions-Reducing Investments at Refineries, Provided they are Adequately and Transparently Justified*

Staff have proposed including credit generating pathways relating to co-processing of biomass feedstock in petroleum refineries as well as from investments in emission-reducing technology. There is ample evidence in scientific literature that both of these pathways can reduce emissions from transportation fuel production systems. Accordingly, **NextGen supports the inclusion of these pathways, provided that sufficient data is made available to CARB and the public to ensure they provide real, verifiable and additional emissions reductions from the full fuel production system they affect.** Specifically, Staff has asked for input on the scope of data which should be provided by developers of these types of projects in order to certify a pathway. Refinery operators, who would be the most common applicants, have argued that data on emissions should be limited to the specific refinery process affected by the proposed investments which would result in credit generation.

Process-specific data is sufficient in cases where the proposed project has no effect on any other process in the refinery. Simple efficiency improvements, such as insulation, displacement of fossil energy by renewable energy for heat or pumping burdens or reductions in waste may be amenable to process-specific analysis. Refineries are complex technological systems in which materials and energy are routinely exchanged between various production units, with coproducts often utilized to maximize production of revenue-generating material and heat exchangers used to recover waste heat. Accordingly, relatively small changes to a single process may have far-reaching indirect effects within the refinery. For example, reducing waste heat from a process may require more energy inputs elsewhere if energy from the waste heat stream was recovered for use in other processes. Improving conversion efficiency in a process may reduce the flow of useful co-products to other processes, necessitating their make-up with additional material. In these cases a consequential, facility-level analysis is the only way to accurately assess actual impacts.

Where project developers claim that a process-specific analysis is sufficient to quantify the emissions reduction attributable to a given project, CARB should require project applicants to provide sufficient data to conclusively demonstrate that there are no significant effects on other processes within the refinery. The burden of proof should rest on the project developer to demonstrate the sufficiency of process-specific analysis

and CARB should err on the side of a more expansive analytical scope where there is uncertainty regarding the scope of impacts. We recognize that some of the data needed to substantiate project developers' claims may be confidential business information, in this case CARB can take appropriate precautions to protect such data, however it must ultimately be made available to CARB and, if applicable, third-party verification bodies. (NEXTGEN1_124-47)

> **Agency Response:** Staff concurs with NextGen's characterization that refineries are complex technological systems with many interconnected units, inputs and flows. As a result any changes to a single process or unit may impact other units or processes. Because of this, the proposed Refinery Investment Credit Pilot Program requires drawing a system boundary that captures at least direct and first order indirect emissions impacts. In most cases, such a requirement will capture the majority of emissions impacts including the examples presented by NextGen above. Since projects will be evaluated on a case-by-case basis, staff may require applicants to include second or higher order indirect impacts if it is determined that those impacts are appreciable. As part of 15-day changes, staff proposed to include a provision requiring applicants to provide evidence that there is no significant indirect impact beyond the identified project system boundary.

L-2.4e. **Comment:** For investments in refinery efficiency, CARB should require that such investments improve efficiency beyond industry standards before they are eligible to generate reduction credits. LCFS credits should only be awarded where investments represent a clear effort to do more than regulation, industry standards or normal retrofit schedules would otherwise require. CARB should seek to develop a set of standards which clearly define industry best practices and use that as a guide to help determine which projects qualify for LCFS credits. CARB should look to resources like global regulatory standards, industry best practice documents and refinery benchmarking efforts.[15]

[15] e.g. the Solomon and Associates refinery benchmark https://www.solomononline.com/benchmarking

(NEXTGEN1_124-48)

> **Agency Response:** The proposed Refinery Investment Credit Program analyzes process improvement projects on a project-by-project basis and recognizes GHG reductions relative to the baseline for a particular project. Although GHG reductions for some process improvement projects may not represent improvements beyond industry standards, the GHG reductions estimated using the method outlined in the Refinery Investment Credit Pilot Program are still real and additional. Development of a refinery benchmark is major undertaking requiring significant resources and staff time. Hence, the inclusion of the refinery benchmark as guide to determine which process improvement projects qualify for LCFS credits is not feasible for the current round of rulemaking.

L-2.4f. Comment: At the same time, we urge ARB to continue to require from parties that the reductions are real and verifiable, consistent with maintain the integrity of the program. (NRDC1_81-18)

> **Agency Response:** The intent of the proposed refinery-related provisions is to establish a quantification framework that is robust and flexible and generates credits that are real and verifiable at the project level.

L-2.5. Multiple Comments: ***Eligible Projects***

Comment: In § 95489(e)(1)(E)4, electrification at refineries that involves substitution of high carbon fossil energy input with grid electricity are eligible projects under the proposal. However, refineries with co-generation facilities do not appear to be addressed in the regulatory language. As electrification takes place within a refinery, a co-generation facility may reduce electricity supplied to the grid system. WSPA requests that ARB provide guidance as to how this situation will be handled in the amended regulations. (WSPA1_21-7)

Comment: WSPA supports the concepts that routine maintenance activities should not earn LCFS credits, nor should shutdowns that predominantly reduce the capability of a refinery to produce the high-specification liquid fuels needed by California motorists. Language that attempts to address this, however, has to be carefully constructed as to not inadvertently exclude projects that have a coincidental shutdown of equipment or even full production units, but is not primarily intending to erode refinery capability.

…

In § 95489(e)(1)(E)(5), WSPA requests that the term “shutdown” in second sentence be replaced with term “curtailment” and the following definition for curtailment be added to the end of this provision:

> “For the purposes of this section, curtailment is defined as an intentional operational and/or physical change exclusively for the reduction or cessation of CARBOB and CARB Diesel manufacture at the refinery. Curtailment does not include the coincidental rate reduction or shutdown of associated emitting equipment as part of a process improvement project or projects aimed primarily at optimizing refinery efficiency.”

(WSPA1_21-8)

Comment: There is a similar concern about the proposed restriction in the latest draft of the rule regarding “crude switching” projects; again, if this language is not written well, projects that the spirit of the program would not intend to exclude could be rejected for consideration upon a narrow interpretation of the language.

…

In § 95489(e)(1)(E)(5), the term “crude oil switching” has been added to the amended regulatory language. As presented, this term could potentially be interpreted in a manner that would inadvertently disqualify viable RICP projects. WSPA suggests that ARB either remove this term or refined it to better reflect the intent of its inclusion in the section. (WSPA1_21-9)

Comment: § 95489. Provisions for Petroleum-Based Fuels
(e) Refinery Investment Credit Program
(1) General Requirements

ARB Proposed Language

(E)5. Process improvement projects that result in carbon intensity reductions per megajoule of total CARBOB and diesel produced. Greenhouse gas emissions reductions due to shutdown, simple maintenance and crude oil switching are not eligible.

Alternative Language

(E)5. Process improvement projects that result in carbon intensity reductions per megajoule of total CARBOB and diesel produced or deliver a reduction in baseline refinery-wide greenhouse gas emissions as outlined in 95489(e)(1)(C). Greenhouse gas emissions reductions due to curtailment, simple maintenance and crude oil switching are not eligible. For the purposes of this section, curtailment is defined as an intentional operational and/or physical change exclusively for the reduction or cessation of CARBOB and CARB Diesel manufacture at the refinery. Curtailment does not include the coincidental rate reduction or shutdown of associated emitting equipment as part of a process improvement project or projects aimed primarily at optimizing refinery efficiency. (WSPA1_21-19)

> **Agency Response:** With regard to the comment concerning eligibility of electrification projects at refineries using cogeneration, if grid export of co-generated electricity is reduced, additional electricity would have to be produced elsewhere to meet overall grid demand. The additional production would be assumed to be California electricity mix. Since co-generation would be considered as part of the system boundary, the net effect would be same as displacing fossil fuels with grid electricity as outlined in 95489(e)(1)(E)4. Hence, a separate treatment for co-generation is not necessary.
>
> To avoid a misinterpretation of the term “shutdown”, staff proposed to replace it with the term “curtailment” as part of the 15-day changes. The term curtailment is defined as an intentional operational and/or physical change exclusively for the reduction or cessation of gasoline/gasoline blendstocks and diesel production at the refinery. Curtailment does not include the coincidental rate reduction or shutdown of associated emitting equipment as part of a process improvement project or projects aimed primarily at optimizing refinery efficiency.

To clarify the meaning of crude switching, staff proposed to add a qualifying phrase in the 15-day changes. Staff proposed to replace “crude oil switching” with “crude oil switching that results in GHG reductions in the project system boundary without improvements in the processing units/equipment involved”.

L-2.6. ***Additional Comments***

L-2.6a. **Comment:** § 95489. Provisions for Petroleum-Based Fuels
(e) Refinery Investment Credit Program
(2) Calculation of Credits

ARB Proposed Language

(B)(3)(A)3. A preliminary estimate of the refinery investment credit, calculated as required in section 95489(e)(2), including descriptions and copies of production and operational data including energy use and other technical documentation utilized in support of the calculation. The production and operational data should cover at least a period of **one year** after the project becomes operational. The application must contain process specific data showing that the reductions are part of the transportation fuel pathway.

Alternative Language

(B)(3)(A)3. A preliminary estimate of the refinery investment credit, calculated as required in section 95489(e)(2), including descriptions and copies of production and operational data including energy use and other technical documentation utilized in support of the calculation. The production and operational data should cover at least a period of **three months** after the project becomes operational. The application must contain process specific data showing that the reductions are part of the transportation fuel pathway. (WSPA1_21-18)

Agency Response: To submit an application for project approval, actual operational data are not required. Preliminary estimates of emissions reductions required in the application can be based on engineering estimates. However, credits are granted only after the actual operational data are submitted and verified. Verification can occur on a quarterly or annual basis. Since the duration of operational data is not a requirement for application submission and project approval, staff proposed to eliminate the one year data requirement in the 15-day changes.

L-2.6b. **Comment:** However, Kern urges ARB to reconsider proposed provisions that continue to place limits on the types and/or duration of projects along with flexible uses of credits generated.

…

As expressed in previous comments, Kern reiterates disappointment with the unnecessary limitation imposed by the finite designation of types of projects proposed,

and the additional limitations imposed on credits generated from process improvement projects. Refineries are under extreme pressure to reduce GHG emissions, which will take equally extreme ingenuity and effort to achieve. Kern urges ARB to rethink the approach to the RICPP and include language allowing broader opportunities for qualifying projects. (KERN1_115-7a)

> **Agency Response:** As part of 15-day changes, staff made several revisions to address stakeholder concerns regarding process improvement projects, the types of projects eligible to receive credits, and the duration of crediting. Please see Responses L-2.3, Crediting Period for Process Improvement Projects, and L-2.5, Eligible Projects, in this chapter.

L-2.7. Multiple Comments: *Stakeholder Recommendations*

Comment: The current regulatory language does pose some barriers on project qualification. So we've made recommendation in our comments to you on that, that we think will enhance the viability of the program, and again continue those incentives for some of that transformation technology. (WSPA4_T48-4)

Comment: The changes we have recommended through WSPA will make the program workable. Every additional project that it may incent in our industry means more jobs, less GHG emissions, and potentially criteria pollution co-benefits; This is a win, win, win. (SHELL1_T50-2)

> **Agency Response:** As part of 15-day changes, staff made several revisions to address stakeholder concerns regarding the RICP program. See responses to comments in sections L-2.2 to L-2.5.

L-3. *Renewable Hydrogen Refinery Credit Program*

Comment: However, as currently worded the proposed regulation governing the Renewable Hydrogen Refinery Credit ("RHRC") Program unnecessarily may limit the sources of lower carbon intensity ("CI") hydrogen and natural gas that refineries could use to generate LCFS credits.

Under the Proposed Regulations, the RHRC Program will award LCFS credits to refineries when "renewable hydrogen" is utilized in the production of CARBOB or diesel.[1] Per Section 95489(f)(2) of the Proposed Regulation Order, there are two methods for calculating credits under the RHRC Program. First, Section 95489(f)(2)(A) provides a credit calculation method for "CARBOB or diesel fuel that is partially or wholly derived from renewable hydrogen produced from RNG that displaces fossil natural gas in a steam methane reforming unit." Second, Section 95489(f)(2)(B) provides a credit calculation method for "CARBOB or diesel fuel that is partially or wholly derived from renewable hydrogen produced from other production processes, such as electrolysis using renewable electricity or syngas from biomass gasification." These are the only two credit calculation formulae offered under the proposed RHRC Program. ARB's Initial Statement of Reasons ("ISOR") clarifies that "RNG" refers to

biomethane and implies that “renewable hydrogen” can be produced only from biomethane or renewable electricity.[2]

[1] Proposed Regulation Order § 95489(f).

[2] ISOR at p. III-81.

Both of the RHRC Program credit calculation methods focus on the difference between the CI of fossil fuel derived hydrogen and the CI of the renewable hydrogen, but a petroleum refinery may apply for credits under the RHRC Program only if it uses “renewable hydrogen” produced from biomethane and/or “renewable feedstock.”[3] Accordingly, other lower-CI methods of hydrogen production appear to be barred from applying for credits and, therefore, excluded from the RHRC Program.

[3] Proposed Regulation Order § 95489(f)(3)(A)(2); ISOR at p. III-81.

Carbon Creek proposes that Section 95489(f) be revised to apply to lower-CI hydrogen more broadly, as opposed to only lower-CI hydrogen derived from particular sources. The Refinery Investment Credit Pilot (“RICP”) Program, as structured in the Proposed Regulation Order, takes this approach. Specifically, Section 95489(e)(1)(E)(3) indicates that eligible project types under the RICP Program include, “Use of lower-CI process energy such as biomethane, renewable propane, and renewable coke, to displace fossil fuel.” In other words, while biomethane is an exemplar of lower-CI process energy the use of which would be eligible to generate credits, the RICP Program is open to any project that would involve the displacement of higher-CI process energy with lower-CI process energy. This approach maintains the environmental integrity of the LCFS without unnecessarily limiting the sources of lower-CI process energy. Moreover, the RICP Program remains true to the design of the LCFS as a fuel-neutral program.

The primary goal of the RHRC and RICP Programs is to reduce the CI of CARBOB and diesel. As the ISOR indicates, RHRC Program projects "have significant potential to reduce the carbon intensities of CARBOB and diesel by introducing transformative technologies thereby contributing to the goals of the LCFS."[4] By democratizing the RHRC Program to encompass all sources of lower-CI hydrogen, ARB will create more opportunities for petroleum refineries to generate LCFS credits and thereby maximize GHG emissions reductions. Further, focusing on the CI of hydrogen used at a refinery rather than identifying particular feedstocks incentivizes the development of innovative approaches to producing lower-CI fuels. Carbon Creek's proposed revisions, detailed below, would support the goals of the LCFS and catalyze additional reductions in GHG emissions.

[4] ISOR at III-50.

Specifically, Carbon Creek proposes that the RHRC Program mimic the RICP Program so that all references to "renewable hydrogen," "RNG," and "renewable feedstock" in Section 95489(f) be replaced with references to "lower-CI hydrogen," "lower-CI natural gas," and "lower-CI feedstock." (CCE1_32-2)

> **Agency Response:** Staff appreciates Carbon Creek’s suggestion on expanding the scope of the Renewable Hydrogen Refinery Credit (RHRC) Program to include low-carbon intensity hydrogen. The RHRC Program is designed specifically to incent novel renewable hydrogen production by recognizing its

potential for significant GHG reductions. Staff understands that there can be other lower-CI hydrogen of fossil (non-renewable) origin, but the potential for GHG reductions is greatly diminished due to the release of fossil carbon which otherwise would have remained underground. Due to limited potential for GHG reductions for other lower-CI hydrogen, staff believes that providing a strong signal for innovative renewable hydrogen pathways would be an appropriate strategy for optimizing LCFS incentives.

M. Carbon Capture and Sequestration

M-1. Multiple Comments: *Support for the Proposed Carbon Capture and Sequestration Provisions*

Comment: Clean Air Task Force (CATF) strongly supports CCS as an integral part of the LCFS and believes CCS must necessarily play an important role in the reduction of fossil carbon emissions in California to enable achievement of California's climate policy goals. (GCCC1_14-1)

Comment: This mechanism of emissions reduction is of high value in reducing risks from release of CO_2 to the atmosphere and I hope that the impact of this work is large and extends far beyond California. (GCCC1_14-4)

Comment: Technologies that utilize carbon capture and storage (CCS) have the potential to be an important tool in the liquid fuel supply chain. Allowing fuel producers to capture and sequester carbon from their own operations is an appropriate means to broaden range of strategies employed to reduce emissions. We support the staff proposal to include credit for direct air capture and sequestration, pursuant to their compliance with the CCS Protocol, and all applicable requirements. CCS keeps in the spirit of the LCFS program's technology neutrality, and will foster new innovations throughout the refining industry. (AJWIOGEN1_17-6)

Comment: *3. On the plus side, the proposed regulations are EXCELLENT as regards the application of the LCFS (Low Carbon Fuel Standard). What this means is that the proposed CCS project must demonstrate that, per lifecycle analysis, it will have an overall effect of reducing GHG's in the atmosphere ... which of course is the purpose of doing CCS at all.* (CSAG1_28-2)

Comment: We applaud California ARB for the substantial amount of work that went into developing the proposed CCS Protocol; it will make for a strong CCS program for the State of California. (RTE1_36-6)

Comment: 2. Carbon Capture and Storage Protocol – We agree that carbon capture and storage (CCS) has tremendous potential in the fight to reduce greenhouse gases. (CRF1_45-4)

Comment: Technologies that utilize CCS have the potential to be an important tool for reducing pollution from the liquid fuel supply chain; California's efforts to create a creditable pathway using CCS, if adopted, may have outsized benefits well beyond the four corners of the state. By allowing technology that is available today to capture and sequester carbon and turn those reductions into marketable commodities, the LCFS can broaden the range of strategies employed to reduce emissions overall, both for fossil fuels and renewable fuels. Furthermore, the LCFS can set an example for the use of CCS in other contexts, yielding positive momentum in the global quest to develop economic tools that can support CCS. Of course, EDF recognizes that additional work must be completed (and program design decisions must be made) before a final CCS

pathway can be embedded in the rule. EDF supports CARB staff collaborative efforts with stakeholders to find solutions to remaining design details and are confident the state can develop a framework that yields positive progress. (EDF1_48-4)

Comment: We support the proposal to account for carbon capture and sequestration (CCS) within the LCFS, in order to accelerate deployment of this critical technology and reduce emissions from the fuel supply chain for both biofuels and fossil fuels.

…

UCS believes that carbon removal technologies have the potential to be an important tool in efforts to keep global temperature rise well below 2 degrees centigrade consistent with global commitments in Paris. The liquid fuel supply chain includes several CO_2 sources that are especially promising opportunities to capture and sequester CO_2, including oil extraction and refining and ethanol production. We support the proposal to adopt a protocol to accurately assess CCS and to ensure that storage is appropriately monitored over time such that risks are mitigated without erecting prohibitively large barriers to developing projects.

The analytical methods that CARB has developed to quantify the lifecycle emissions of fuel pathways are state of the art, and adding CCS to these tools will make them more useful. The science in this area will certainly continue to develop as industry moves forward with projects and regulators get experience with the review and approval of pathways. Given the nascent development of this technology, we encourage CARB to be pragmatic and flexible as technology develops and industry and regulators gain experience. We also encourage CARB to hold workshops, seek external review and make updates over time, as the state of knowledge improves.

Allowing CCS in the fossil fuel supply chain to qualify for credit generation under the LCFS is an appropriate means to hold the oil industry accountable to reduce its emissions. Other policy approaches, such as the recently modified 45Q federal tax credit, provide subsidies for CCS that are ultimately paid for by the public. By contrast the LCFS provides a powerful motivation to move forward CCS projects, but the funds come not from public coffers, but from credits paid for by sellers of high carbon intensity fuels, principally gasoline and diesel. Thus, while LCFS credits may be very valuable, they do not constitute a subsidy, but are instead a science-based mechanism through which fuel producers in the fossil fuels industry can partially fulfil their obligations to reduce fuel carbon intensity under a performance standard. Decarbonizing the fuel supply chain will require action to reduce emissions from both innovative new transportation fuels, and existing fuels, and adding CCS to the available compliance options under the LCFS in conjunction with setting more ambitious targets is an important improvement to the policy. (UCS1_53-7)

Comment: Fifth, we support the proposal to account for carbon capture and sequestration within the LCFS in order to accelerate deployment of this critical technology and reduce emissions from the fuel supply chain for both biofuels and fossil fuels. (UCS2_T53-7)

Comment: Occidental Petroleum appreciates CARB's leadership role in developing the LCFS's CCS protocol and submits these comments in support of the proposal. Many of the world's leading climate research organizations have recognized CCS as an essential tool for achieving the carbon dioxide (CO2) emission reductions necessary to meet California and global climate goals. We believe that the influence CARB wields beyond California's borders can enhance public confidence in CO2 reductions made via geologic sequestration. It is vital to the success of CCS as a carbon mitigation tool to create a CARB standard that is robust and transparent while encouraging responsible parties to develop the full potential of CCS. (OCCIDENTAL1_63-1)

Comment: Injecting CO2 into mature oil reservoirs can increase ultimate oil production by 10 to 25 percent. Outside of California, Occidental produces an additional 150,000 barrels of oil equivalent per day through EOR. EOR presents an alternative to "greenfield" exploration and productions in newly discovered fields and could displace oil produced using more energy intensive operations. Based upon research by the International Energy Agency (IEA), it has been shown that CCS in the form of EOR with anthropogenic CO_2 can provide a significant reduction in life-cycle per barrel CO_2 emissions compared to oil produced using non-EOR techniques (https://www.iea.org/publications/insights/insightpublications/CO2EOR_3Nov2015.pdf). EOR using anthropogenic CO_2 could enable develop of a lower carbon transportation fuel to help further reduce greenhouse gas emissions.

There are several advantages to geologic sequestration of CO2 accomplished by employing enhanced oil recovery. As with other geologic sequestration, the first and most important decision is selecting the right site. A well-selected site with no transmissive faults or fractures is the best defense in ensuring that leaks are prevented and that CO2 stays within the area of the rock inside the formation that was intended. It goes without saying that sites with faults and fractures that might provide pathways for CO2 to escape sequestration should never be used for geologic sequestration. Operators engaged in CO2 EOR have detailed knowledge of their producing formations and geological conditions. This knowledge is essential to maintaining the injection rate of an EOR flood equal to the withdrawal rate. In turn, constant injection and withdrawal rates ensure that constant pressure in the reservoir is maintained, which is necessary to maximize the production of the oil. This constant pressure, which is very close to the original reservoir pressure prevents the chance of over-pressurization which could lead to damage to the cap rock layer above the reservoir. It also prevents any risk of forcing the CO2 into other geologic zones.

After faults and fractures, the biggest risk of leakage in EOR operations are penetrations (i.e., well bores) into the rock comprising the sequestration zone. States likes California and Texas have extensive experience, understanding and regulations that require the identification and proper plugging and abandoning of unused wells. It is also important to have robust well and mechanical integrity management systems in place so that potential issues are avoided through the maintenance and care of existing wells. Additionally, leak detection and repair programs are vital. We cannot overemphasize the importance of these requirements which, combined with this protocol, will eliminate future risks of leak from CO2 sequestration. Moreover, as

mentioned before, all of these programs and systems are critical to operating a successful EOR project.

In closing, Occidental thanks CARB for considering the inclusion of carbon capture and sequestration accomplished through EOR as part of its low carbon fuel standard and as part of the state's strategy to reduce CO2 emissions by all means practical. With over 40 years of successful implementation, geologic sequestration of CO2 accomplished during EOR is a verifiable, proven and safe technique for avoiding and reducing CO2 emissions. Since the EOR operator purchases CO2 as a process "feedstock", there is an economic incentive for those that capture their CO2 emissions that other forms of geologic sequestration do not offer. Additionally, many of the techniques and tools needed to successfully operate a CO2 flood are the same tools and techniques needed to monitor the CO2 to assure it stays within the area of review and necessary to quantify the amount of CO2 that is sequestered. Therefore, EOR offers a low cost, proven approach to CO2 sequestration.

As a leader, California is poised to demonstrate the path forward for other states and countries. Your decisions will likely have influence far beyond California's borders. We encourage you to include EOR as part of your suite of solutions, we commend you on the amount of transparency and inclusion with which you and your excellent staff has approached this process. We welcome the opportunity to offer our experience and expertise in CO2 EOR technology and look forward to the finalized framework. (OCCIDENTAL1_63-2)

Comment: I'm here to explain Occidental's support of inclusion of the carbon capture and storage part of the Low Carbon Fuel Standard.

Many of the world's leading climate research organizations have recognized that CCS is an important tool for achieving CO2 emission reduction goals set by California but also other organizations throughout the world. (OCCIDENTAL2_T7-1)

Comment: Oil produced using CO2 presents an alternative to greenfield exploration and production in newly discovered fields and could displace -- … -- and could displace more energy intensive operations. (OCCIDENTAL2_T7-4)

Comment: CIPA is in very strong support for CARB's efforts and recognition of the benefits of Carbon Capture and Storage (CCS) for Enhanced Oil Recovery (EOR) operations. As pointed out in CARB's Scoping Plan, liquid fuels will be a significant component of California's transportation fuel mix for decades to come. It is also known that to achieve the longer-term greenhouse gas reduction goals, that CCS is an important policy to pursue. These two issues are interlinked. It does not make sense to pursue CCS if EOR is not an eligible activity. Staff is proposing this opportunity for industry, and the industry will rise to meet the challenge. Any thought that EOR related CCS should be removed from the rule would be significant negative policy decision. (CIPA1_71-7)

Comment: 7. NRDC supports the inclusion of accounting and permanence requirements for ethanol facilities, petroleum refineries, and crude oil producers that reduce their carbon intensity using carbon capture and sequestration.

Carbon capture and sequestration technologies have the potential to be a crucial tool in efforts to keep global temperature rise below 2 degrees centigrade, consistent with the Paris Accord. Several carbon dioxide sources in the liquid fuel supply chain, including oil extraction and refining, and ethanol production, provide especially promising opportunities for capturing and sequestering carbon dioxide. A recent report prepared by Cerulogy Research for NextGen Policy Center showed significant potential for the technology to be deployed and contribute towards achieving LCFS targets.[4]

[4] https://www.arb.ca.gov/lispub/comm/bccomdisp.php?listname=lcfs18&comment_num=5&virt_num=5

The Board voted years ago to allow all fuel producers to capture and sequester carbon dioxide from their own operations as another way to broaden the range of strategies employed to reduce fuel-production emissions. Pursuant to past direction by the Board, ARB staff has now devoted several years' worth of work into developing the technical framework that will be used to ensure permanence of the sequestration and govern the relevant accounting. We welcome ARB's efforts, and have actively participated in every step to date.

The proposed CCS Protocol under the LCFS represents the most comprehensive piece of CCS regulation by any jurisdiction, and goes to great lengths to ensure the safe and sound selection, operation, decommissioning and monitoring of CCS projects. NRDC has devoted considerable time and attention to the science and regulation of CCS for well over a decade now, and are encouraged by the level of detail, prevention and diligence that ARB has incorporated into the Protocol. We are providing separate technical comments on ways to further improve the Protocol, and encourage ARB to ensure that environmental risks are mitigated without erecting prohibitively large barriers to developing projects that would further the achievement of California's climate goals. (NRDC1_81-16)

Comment: Carbon capture and storage could play an important role in our climate mitigation efforts. CARB's proposed accounting and permanent standards would protect public health and the environment while giving the technology and opportunity to reduce emissions and the carbon intensity of transportation fuels and reduce emissions from large sources.

In many cases this technology could also lead to local air quality improvements.

Now, as someone with firsthand experience operating a CO2 injection project, I can attest to two things:

First, existing practices and regulations alone cannot be relied upon to ensure permanent CO2 storage. As such, ARB's multi-year effort that has culminated in this protocol meets a critical need.

Second, the protocol goes to great lengths to ensure that projects are sited, operated, and decommissioned soundly with permanence always in mind. In fact, this is the most comprehensive and protective piece of CCS regulation ever compiled by any jurisdiction. (NRDC2_T19-5)

Comment: We thank CARB staff for its focused hard work, and the Board for its vision and leadership in this area. We urge you to adopt this critical protocol with the important changes we've suggested. (NRDC2_T19-9)

Comment: CATF appreciates the effort that the CARB has invested in developing the Protocol and strongly supports CCS as an integral part of the LCFS. CATF believes CCS can play an important role in the reduction of fossil carbon emissions in California.

This letter provides our comments on the Protocol, which we believe will serve to strengthen it. We recognize that many hours have been spent by the staff developing the draft and we appreciate the opportunities that CARB has provided for input over the past several years.[1] Please note that we have also co-submitted, with Dr. Susan Hovorka from the University of Texas, an edited version of the Protocol. That submission, however, did not include CATF's input pertaining to sections B.3, C.1, C.5, C.7, and appendix G. Those provisions are conceptually addressed in this letter, with proposed language to implement the recommendations included in the attached redline.

[1] John Thompson, CATF, PowerPoint, "CCS Perspectives and Recommendations on Quantification Methodologies," (Feb. 12, 2016), *available at*: https://www.arb.ca.gov/cc/ccs/meetings/CATF_Presentation_2-12-16.pdf; Bruce Hill, CATF, PowerPoint "Considerations in Developing QM for EOR Storage," (Aug. 23, 2016), *available at:* https://www.arb.ca.gov/cc/ccs/meetings/CATF_Presentation_8-23-16.pdf; Bruce Hill, CATF, Testimony at ARB Public Workshop, (Feb. 12, 2016), *available at:* https://www.arb.ca.gov/cc/ccs/meetings/CATF_Comments_2-12-16.pdf; Bruce Hill, CATF, "Comments to ARB on Quantitative Methodology, Accounting," (Apr. 28, 2016), *available at:* https://www.arb.ca.gov/cc/ccs/meetings/Bruce_Hill_CATF_Comments_4-28-16.pdf; Letter from Jeffrey Bobeck, Global Carbon Capture and Storage Institute, *et al*., to Alexander Mitchell, ARB, (May 30, 2017), *available at:* https://www.arb.ca.gov/cc/ccs/meetings/Various_Comments_5-30-17.pdf; Letter from Jeffrey Bobeck, Global Carbon Capture and Storage Institute, *et al*., to Samuel Wade, ARB (Oct. 20, 2017), *available at*: https://www.arb.ca.gov/fuels/lcfs/workshops/10202017_coalition.pdf; Letter from Jeffrey Bobeck, Global Carbon Capture and Storage Institute, *et al*., to Samuel Wade, ARB (Dec. 4, 2017), *available at*: https://www.arb.ca.gov/fuels/lcfs/workshops/12042017_coalition.pdf.

(CATF1_100-1)

Comment: CATF fully supports and appreciates CARB's efforts to admit CCS into the LCFS. As we all know, the IPCC modeling suggests that meeting even the 2-degree climate goal will be extremely costly and difficult without the use extensive of CCS. So, kudos to CARB for taking a leadership role in creating a pathway for CCS to play its role in climate change mitigation, starting with the transportation sector. (CATF2_B14-1)

Comment: CATF fully supports and appreciates CARB's efforts to admit CCS into LCFS. And as we've heard before, IPCC modeling suggests that meeting the 2-degree climate goal will be extremely costly and difficult without the extensive use of CCS.

So kudos to the team at CARB for taking a leadership role in creating a pathway for CCS to play its role in climate change mitigation starting with the transportation sector.

We believe that LCFS credit market will provide an added economic incentive for more CCS projects to be developed, which will help meet California's climate goals, near-term and mid-century climate goals. But not just that. We believe that the LCFS credit market will catalyze a CO2 reduction industry even outside of California, laying the foundation for deep decarbonization across the U.S.

A CO2 reduction industry is -- could emerge in the form of a network of capture, transport, and storage infrastructure that could eventually deliver several millions of tons of emissions reductions on an annual basis.

…

In conclusion, I would emphasis that CATF really supports CCS and its inclusion in the LCFS rule. (CATF3_T41-1)

Comment: The California Air Resources Board's (CARB) effort to admit CCS under California's climate programs, provided adequate safeguards are met, is a critically important effort that could help in- and out-of-state projects contribute to California's climate mitigation efforts and the reduction in carbon intensity of fuels used in the state. (CCSPD1_106-1)

Comment: The proposed CCS Protocol likely represents the most comprehensive effort to date on regulating CO_2 emissions to the air from CCS projects. We thank CARB staff for its focused and hard work in this area over the past few years. We believe that, even though not simple, the proposed Protocol contains many sound elements and goes a long way towards meeting its multiple objectives. However, some key technical changes are also necessary, which we believe can be readily accommodated within the architecture of the proposed Protocol. Contingent on these changes, the undersigned anticipate supporting adoption of the final version of the Protocol. (CCSPD1_106-4)

Comment: Carbon capture and storage technologies have the potential to be an important tool in efforts to keep global temperature rise below 2 degrees centigrade consistent with global commitments in Paris. Several carbon dioxide sources in the liquid fuel supply chain, including oil extraction and refining, and ethanol production, provide especially promising opportunities for capturing and sequestering carbon dioxide. We encourage CARB to ensure that risks are mitigated without erecting prohibitively large barriers to developing projects. Allowing all fuel producers to capture and sequester carbon dioxide from their own operations is another way to broaden the range of strategies employed to reduce fuel production emissions. (COALITION1_107-5)

Comment: Chevron is supportive of the use of CCS projects to reduce the carbon intensity of fuel pathways and generate innovative crude and refinery investment credits. (CHEVRON1_112-12)

Comment: We strongly support the development of a CCSQM to provide a pathway for the LCFS. Given California's pursuit of a 40 percent 2030 goal, all pathways and efforts to reduce should be facilitated through technically sound and risk-based criteria.

We thank the staff for their work to create this CCSQM; and with a few notable exceptions, we agree with it. (CHEVRON2_T33-1)

Comment: We agree with the current QM's overall technical premise that CCS projects must be evaluated based on site-specific conditions, and that operations are monitored using appropriate technologies. (CHEVRON2_T33-3)

Comment: *NextGen Supports Adding a Carbon Capture and Sequestration Protocol*

Staff have proposed to add a credit generation pathway to reflect carbon capture and sequestration (CCS) to the LCFS. CCS can include a variety of methods of durably storing carbon in a manner which prevents it from returning to the atmosphere. Within the scope of transportation fuel production, the most applicable form of CCS is likely to be capture of carbon dioxide gas, compression and injection into geologic storage sites such as underground caverns, depleted petroleum reservoirs and saline aquifers. CCS is a relatively new technology; there are a limited number of demonstrations projects at present, but there is a board consensus in the extant literature that CCS is technologically feasible, scalable and could become cost effective, especially in jurisdictions which adopt a carbon price. While it may be possible for California to attain its clean energy goals without using CCS, most projections of energy system deployment compatible with limiting climate change to well below 2 degrees Celsius of maximum warming require a significant deployment of CCS.[10] California can continue to demonstrate its global climate leadership by helping deploy CCS at commercial scale to demonstrate the technology and begin driving costs down to commercially-viable levels.

[10] e.g. https://www.ipcc.ch/report/ar5/

(NEXTGEN1_124-23)

Comment: The combination of LCFS credits and Federal Section 45 (Q) tax credits could ultimately yield net revenue of over $150 per tonne for sequestered carbon, well over the value that multiple authors have concluded is necessary to support industrial-scale CCS in a variety of near-term applications.[12] We feel that the incentive provided by the LCFS and 45 (Q) credits is likely to be sufficient to support the deployment of a sufficient number of early projects, which will provide critical support for the CCS industry while providing valuable experience to CARB regarding real-world performance and regulatory considerations. NextGen and the Union of Concerned Scientists evaluated the potential for near-term deployment of CCS projects under the LCFS and found there was significant potential in at least two categories: capture of ethanol fermentation tank emissions and as modification to steam methane reformers (SMR) at existing petroleum refineries.[13] These two pathways take advantage of high-concentration or high partial-pressure streams of CO_2 that occur in existing industrial processes. These streams offer a favorable environment for capturing CO_2 at relatively low cost, which makes them likely options for early commercial deployment.[14]

This analysis concluded that there was potential for several hundred thousand to several million tonnes of CO_2 sequestration per year through 2030 from these sources.

[12] http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapCarbonCaptureandStorage.pdf

[13] Add URL for re-submitted CCS memo here.

[14] See: D.L. Sanchez, N. Johnson, S. McCoy, P.A. Turner, K.J. Mach. "Near-term deployment of carbon capture and storage from biorefineries in the United States" Proceedings of the National Academies of Sciences (In Press). for more information on CCS at ethanol facilities and "Current Central Hydrogen Production from Natural Gas with Sequestration" at https://www.hydrogen.energy.gov/h2a_prod_studies.html for more information on CCS at steam methane reformers.

(NEXTGEN1_124-29)

Comment: Carbon capture and atmospheric removal technologies may offer large reductions in net emissions but also present scope and boundary challenges for the LCFS. Some carbon capture opportunities fit squarely within transport fuel production: capturing and sequestering existing emissions streams from fuel production or processing, and producing low-CI synthetic fuels using carbon removed from the atmosphere. But the larger potential contributions of carbon capture or removal lie outside transport fuel production as presently defined. Counting carbon removal elsewhere or in other processes as reducing the CI of a transport fuel would require drawing artificial system boundaries for the CI calculation, under which the carbon capture or removal function more like offsets than emissions reductions. The associated boundary-drawing challenges are not just theoretical matters of what cuts really count as being in transport fuel. They also affect high-stakes practical issues of potential harms or scale limits in total carbon removal, when billions of tons of annual removals are already widely assumed and using carbon removal to offset substantial continuing gross emissions from transport fuels would represent a further large increase.

These concerns highlight the importance of keeping careful control over the pace of expansion of LCFS crediting for technologies, like carbon capture and removal, that may have large potential and flat marginal costs, but that may be judged not to comprise complete solutions to reducing transport emissions. The treatment of CCS in the current proposed amendments, crediting removals on site with fuel production processes or atmospheric removals incorporated into fuel products, strikes an appropriate and prudent balance. Further expansion of crediting for carbon capture or removal may be judged warranted in the future, but must be carefully controlled and gradual. (UCLA1_B8-5)

Comment: I wish to bring to your attention a new paper "Near-term deployment of carbon capture and sequestration from biorefineries in the United States" published by Sanchez et al. in *Proceedings of the National Academy of Sciences*. It is open source, and available at this address:

http://www.pnas.org/content/early/2018/04/18/1719695115

This paper suggests a substantial opportunity produce lower carbon-intensity (CI) ethanol in California, or import lower-CI products from out of state. It is my hope that

these results will be useful to the Board when considering Low carbon Fuels Standard policy, including adoption of the carbon capture and sequestration quantification and permanence methodologies. (CIS1_B9-1)

Comment: The LCFS modifications are valuable because they continue to drive technology innovation that's going to be required for even greater challenges to come. After all, the 2030 goals are only a point on a curve where the State has a goal to reduce its emissions by 75 percent at 2050. And beyond 2050, it's looking pretty clear like we have to be better than zero emissions. We're going to have to start taking CO2 out of the atmosphere and have other negative carbon approaches.

So achieving such ambitious goals, of which this is one important step, requires that we have all of the tools available to us on the table.

And one of the most important tools which has been used around the world to some degree that these changes encourage are carbon capture and sequestration -- geologic sequestration.

It's not widespread around the world but certainly there are very substantial demonstration projects that have allowed testing of technology, the development of scientific techniques, including techniques to monitor that allow one to assess the condition of the reservoirs when things start to go badly.

For example, we managed to image using tools that had their origins in the national security environment to identify stresses to the cap rock before CO2 was released and the sequestration project ruined.

Carbon capture in Norway has been going on for 20 years. The national laboratories of the DOE have been involved in all of these projects and know that there are tools to manage the risks. The risks are real - risks to the groundwater, risks to leakage - but those can be managed and the risks mitigated through careful monitoring.

So we're in strong support of this as part of a tool chest to reach goals which are going to get tougher with time to meet. (LLNL1_T29-2)

Comment: We fully support Low Carbon Fuel Standard and … in particular the CCS protocol. In battling climate change we believe CARB needs to deploy all of the available tools it has today to reduce greenhouse gas emissions. CCS we believe is a proven technology with proven GHG reduction capabilities.

We also believe ethanol companies are a perfect partner for implementing CCS -- our CCS while continuing to provide low-carbon fuel to the State of California.

...

To close, you know, we fully support ARB’s work in reducing GHG emissions and applaud the inclusion of the CCS in the newest protocol. (WE2_T34-2)

Comment: One thing I just wanted to address, we're very supportive of the carbon capture and storage protocol. We definitely need that in there and we hope that we'll continue to have progress. That has been very difficult. We've been working on that for a long time. For somebody who is working on the forestry protocol about 10 years ago, I know how difficult it is at putting these protocols together.

…

So again, support the CCS effort. (CONESTOGA1_T39-1)

Comment: And I'm here today to speak strongly in favor of the uses of CCS for generating credits under LCFS. So as a life-long Californian, and as a geologist, and working with my group at LBL, geothermal energy, and energy storage as well as CCS, really seeing how California geology is very amenable to CCS.

We've gained a lot of knowledge about CCS over the 20 years, and we can really say that it's very viable in California, as well as in other places across the country. The fact is California possesses an enormous opportunity for CO2 storage. The Central Valley of California has a sedimentary sequence of enormous thickness providing huge opportunities. And there are similar opportunities across the U.S.

So CCS is a technology that can be applied to the whole range of stationary CO2 sources, with capture coming from power plants to refineries from cement plans to biofuel and bioenergy plants. So taken together, with geologic formations existing, that provide this enormous opportunity in California, as well as across the country, and having large stationary sources across the country and here, at which carbon can be captured, it's really a very viable opportunity going forward.

And, in short, I would say that it's -- can be considered an available technology to reduce CO2 emissions from stationary sources, among which are these biofuel plants. Now, California clearly needs all of the tools that it has available. This is one that we have available.

So I'm very confident that CCS can be carried out successfully within the LCFS program to help meet California's greenhouse gas emission goals. (LBNL1_T45-1)

Comment: Third, you've heard a lot on carbon capture sequestration. We very, very much support work in this area. It really does reduce the impact -- carbon impact of what we do. And we see it as a very viable entity. I'm not going to -- I'll just support Chevron's comments and previous comments made. (WSPA4_T48-6)

Comment: Finally in the long term, we need to see uptake of CCS globally and at scale. We at Shell see no credible path to net zero carbon as soon as 2070 without it, as outlined in our recently published Sky Scenario.

Towards this aim, we very much appreciate the efforts by staff at ARB to develop protocols for CCS and support a protocol being promulgated. (SHELL1_T50-4)

Comment: Good afternoon, Madam Chair and members Pete Montgomery here on behalf of the Global CCS Institute in strong support of the inclusion of the Low Carbon Fuel Standard of a protocol and quantification methodology for CCS. The Institute is an international member-led organization, and our mission is to accelerate the deployment of CCS for tackling climate change and energy security.

I wanted to focus my comments quickly today on making sure it's clear that CCS is not a future solution. CCS is a real functioning technology that is in operation around the world. There are 17 large-scale CCS facilities in operation globally, with four more coming on line in the next 12 months. These 21 facilities capture and permanently store 37 million tons of CO2 per year, which is the equivalent of taking eight million cars off the road.

In the Institute's 2017 report on the global status of CCS reported that 220 million tons have been documented to have been stored to date. In North America alone, there are 12 operating facilities, 10 on industrial applications and two on power plants. Recently, I've had the pleasure of taking CARB staff to visit two of these operating facilities: NRG's Petra Nova plant outside of Houston, which is the world's largest post-combustion project; and ADM's industrial carbon capture and storage project at their ethanol plant in Decatur Illinois.

The Institute has worked closely with a broad coalition of stakeholders that have submitted comments detailing the critical nature of CARB adopting workable CCS regulations as part of the LCFS. And we support the call for the Board to direct staff to work to ensure that what gets incorporated into the LCFS does not provide a barrier to near-term deployment of critically needed CCS projects.

This technology is being deployed around the world to reduce CO2 emissions, and we look forward to California getting in the game. (GCCSI1_T51-1)

> **Agency Response:** Staff appreciates the commenters' support for the inclusion of the CCS Protocol in the LCFS. Staff agrees that the addition of CCS to the LCFS will provide a resource for traditional and alternative fuel producers to utilize in an effort to lower the CI of fuels in California.

M-2. Multiple Comments: *Definitions*

M-2.1. Multiple Comments: *Definitions of "Storage Complex" and "Elevated Pressure"*

Comment: I made two global comments:

1) Modify the "Storage Complex" definition to include the predicted volume needed to contain the plume until stabilization. This is needed to achieve the permanence required. Substitute "Storage Complex" for "Area of Review (AOR)" in places where a three-dimensional volume is needed throughout. A two-dimensional area at the land surface may lead to inclusion of shallow

features not relevant to achieving permanence and not include all deep features, e.g. deviated wells.

2) Change “pressure front” to “elevated pressure” throughout. The distribution and magnitude of pressure change resulting from injection should be measured assessed, and reported, and not be reduced to a linear feature. The details of pressure evolution of the whole plume is needed to validate models and manage injection. Mapping a “front” may miss highest pressure elevations and greatest risk, and a front will be undefined in many cases, for example in artesian saline formations and in cases where production creates a pressure sink at the project. (GCCC1_14-7)

Comment: II. “Storage Complex” and “Elevated Pressure” Should Define Investigation and Monitoring.

The “area of review” (AOR) and plume and pressure front concepts are adopted from the Federal Underground Injection Control Rule Class VI requirements, which are integral to the Safe Drinking Water Act and protection of groundwater from brine intrusion. Much has been learned since the promulgation of that rule.

First, the risk of elevated pressure that is referred to in the Protocol as a pressure front pertains to protection of groundwater supplies. The underlying concern pertains to the risk of driving saline brine into freshwater aquifers rather than CO_2 leakage to the atmosphere. Imposing this requirement across all project types could unwittingly result in an unreasonably large review volume, in some cases, infinite, such as where there is natural hydrostatic pressure emanating updip from the formation - as possibly present California’s mountainous regions.

Second, the pressure front itself can be a misleading conceptual model for describing how injected CO_2 interacts with reservoir formations, given the subsurface heterogeneity in mineralogy, grain size, cements, composition, and structures. Pressure may extend outward from an injection well, but it is incorrect to think of it as a circumference of pressure extending radially from the injected CO_2 location, but better instead to conceptualize response as “areas of elevated pressure.” Furthermore, in EOR projects, injection wells are surrounded by production wells which generate low pressure around them, and therefore a pressure front approach cannot effectively be applied to EOR projects. To easily remedy this, Dr. Hovorka’s edited Protocol submission further recommends elimination of the word “front” to be replaced globally in the document with “elevated”, thus, “elevated pressure.”[2] In concert with this change, we recommend replacement of the “area of review” (AOR) and instead recommend defining the review volume using the term already defined in the Protocol, “storage complex,” meaning the volume of rock that is predicted to contain the CO_2 plume permanently.[3] Under this recommended approach, the terms “elevated pressure” and “storage complex” will apply to both saline brine and EOR projects. For example, within the storage complex, all subsurface permeability zones, fracture zones, faults, and legacy wells that are transmissive with potential for induced seismicity will be risks that are identified and corrective action will be taken to avoid leakage. These conditions will then be monitored to determine if the corrective action was successful, and to determine

whether these features pose risks to permanence. The term “area of review” (the surface overlying the storage complex) should then be only used to define important *surface* resources.

In summary, the maximum acceptable space for the CO2 plume to migrate should be a volume rather than an area. As an example, a horizontal well drilled outside an AOR might be derived into the storage complex volume at depth. A three-dimensional review will assess risk from all sources. Therefore, for all projects, we recommend that CARB require a three-dimensional model of the “storage complex” with all of the risk zones highlighted, and the approach to monitoring the risk zones included.

“…modeling of the ~~AOR~~ Storage Complex evaluation…” (CATF1_100-3)

Comment: Critical consideration must be given to the fact that CO_2 injection and resultant changes in formation pressure are managed through production in EOR. In EOR fields, injector wells are at the center of a pattern of production wells which produce effective low-pressure zones, and therefore the concept of a pressure front is not relevant. One simple modification in the Protocol, as described above, would significantly improve the efficacy of the overall approach by changing the term “pressure front” to areas of “elevated pressure” globally, throughout the Protocol. (CATF1_100-4a)

Comment: “Storage Complex” concept should replace “Area of Review” for delineating certain project requirements

The AOR approach is derived from the Federal Underground Injection Control Class VI requirements, which are integral to the Safe Drinking Water Act and protection of groundwater from brine intrusion. Much has been learned since the promulgation of that rule. First, the risk of elevated pressure that is referred to in the Protocol as a pressure front pertains to protection of groundwater supplies. The underlying concern pertains to the risk of driving saline brine into freshwater aquifers rather than carbon dioxide leakage to the atmosphere. Imposing this requirement across all project types could unwittingly result in an unreasonably large review volume, in some cases, infinite, such as where there is natural hydrostatic pressure updip from the formation (including the the Sierra Nevada in California). Second, the pressure front itself is an outdated concept. Pressure may extend outward from an injection well, but it is incorrect to think of it as an approximate circumference of pressure extending radially from the injected CO_2 location, but better instead to conceptualize as “areas of elevated pressure”. Furthermore, in the enhanced oil recovery (EOR) context, injection wells are surrounded by production wells which generate low pressure around them. A pressure front approach therefore cannot effectively be applied to manage risk in EOR projects. To remedy this, we recommend elimination of the word “front” and replace with “elevated pressure.” In concert with this change, when referring to the subsurface and 3-dimensional volume, we recommend replacement of the “Area of Review” concept and instead recommend defining the review volume using the term already defined in the Protocol, “storage complex”, meaning the volume of rock that is predicted to contain the CO_2 plume permanently.

Under this recommended approach, the terms “elevated pressure” and “storage complex” would then apply to both saline brine and EOR projects. For example, within the storage complex, all subsurface permeability zones, fracture zones, faults, and legacy wells that are transmissive with potential for induced seismicity would be risks that are identified and corrective action would be taken to avoid leakage. These conditions would then be monitored to determine if the corrective action was successful, and to determine whether these features pose risks to permanence. The Area of Review (the surface overlying the storage complex) should then be only used for requirements that pertain to the *surface*, or for leakage pathways that may extend vertically above the storage complex. CARB should require a three-dimensional model of the storage complex with all of the risk zones highlighted, and the approach to monitoring the risk zones included. This will also ameliorate the problem with the concept of an area of review. The maximum acceptable space for the CO_2 plume to migrate should be a volume rather than an area. An example, a horizontal well drilled outside an area of review might be deviated into the storage complex volume at depth. A three-dimensional review will assess risk from all sources. (CCSPD1_106-5)

Comment: Critical consideration must be given to the fact that formation pressure changes resulting from CO_2 injection are managed through production in EOR. In EOR fields, injector wells are at the center of a pattern of production wells that produce effective low-pressure zones, and therefore the concept of a pressure front is not relevant. One simple modification in the Protocol would significantly improve the efficacy of the overall approach, by changing “pressure front” to “areas of elevated pressure.” (CCSPD1_106-10a)

> **Agency Response:** Staff agrees with the commenters’ concerns that the term “pressure front” is not sufficient to describe the true pressure response of the sequestration zone related to injection. Staff understands that the distribution and magnitude of pressure changes resulting from injection is not a two-dimensional, spherical feature, and that it is necessary to measure and assess the pressure evolution of the whole plume in order to correctly account for leakage risk. Staff also understands that, because pressure changes resulting from injection are managed by production in CO_2-EOR operations, there is no measurable “front” in EOR. Therefore, in response to these comments, staff modified subsection A.2.(a) of the Protocol by removing the definition of “pressure front” and adding the definition of “elevated pressure.” Staff also replaced the term “pressure front” with “elevated pressure” in all instances of the Protocol.
>
> Staff also agrees with commenters’ argument that the term “area of review” is not sufficient to describe the three-dimensional storage volume and all geologic layers and structures that impede the lateral or vertical migration of the CO_2 plume. Therefore, staff modified the definition of “storage complex” in subsection A.2.(a) of the Protocol to include a sequestration zone, confining system, and any other layers/structures that may serve as dissipation intervals or help to retard CO_2 plume migration. In the proposed Protocol released June 20, 2018, the term “area of review” was used to refer to the *two-dimensional surface footprint*

of the CO_2 plume (please refer to Response M-2.3 in Chapter V in response to comment CATFNRDC1_FF55-32). In the proposed Protocol released August 13, 2018, staff deleted the definition of "area of review" from subsection A.2.(a) and removed all instances of the term in the Protocol, in response to comments (please refer to Response M-2.2 in Chapter VI). Staff used the term "surface footprint of the storage complex" in place of AOR.

M-2.2. Multiple Comments: ***Definitions of "Confining Layer" and "Dissipation Interval***

Comment: It is incorrect to define a seal strictly in the context of San Joaquin Valley geology that is characterized by a thick sequence of shale overlying the potential saline reservoir sequence (that furthermore must be tested for its capillary entry pressure and ductility). We recommend that CARB broaden its concept of a seal to include a sequence of rocks (confining system) with the demonstrated ability to secure CO_2 permanently (meaning on a geologic time scale). A sealing/trapping sequence need not be narrowly defined as a shale as a result of the testing requirement, (e.g evaporites, carbonates, etc). It is acceptable to keep such types of tests as an option in the Protocol, but we recommend that CARB eliminate these tests as fundamental *requirements* in the it. (CATF1_100-7a)

Comment: Dissipation interval, defined at (44), is an approach recommended in the 2017 white paper prepared at the request of the CARB by Lawrence Berkeley National Laboratory (LBNL). While the LBNL provides potentially useful criteria for application in certain parts of California, the approach has the following fundamental flaws when utilized as a general global approach:

1. Rock sequences are by their very nature heterogeneous. For example, in the San Joaquin Valley, the sands are fluvial in origin which means they may be laterally discontinuous (imagine an ancient meandering river) however robust they may look in a wellbore or core sample. The requirement to present three clear zones may lead to inaccurate geologic section descriptions.
2. Out-of-state projects qualifying under the LCFS will likely have very different geological settings, such as carbonate sequences where a pressure dissipation interval does not exist, yet the storage complex is demonstrably secure for permanent storage (e.g., reservoirs of the Permian Basin capped with salts).
3. A storage complex should be defined as a sequence of rocks that will contain CO_2 permanently, and the pressure dissipation interval, if present, is an asset.
4. A pressure dissipation interval could be used as a primary storage reservoir given that, by definition, that interval must be overlain by a robust seal.
5. The LBNL approach ignores that projects that qualify for the LCFS may be in other states. Dissipation interval (also AZMI) may be a positive qualifying attribute for monitoring and as a secondary storage compartment above the primary seal, but this attribute should *not* be required. Applying the LBNL approach globally could eliminate many secure sites.

Our recommendation is that ARB eliminate "dissipation interval" at definition (106) (a) as integral to storage complex and as a requirement at 2.1 (a)(4) and (5). Instead we suggest it can remain in the Protocol as an optional feature (e.g. as required in the storage complex geologic description in 2.3 (C)(3)(c)(5)) that could provide lower risk in some projects. Moreover, the interval, if present, may be useful for above – zone monitoring or mitigation – if it is not being considered as a primary storage zone. (CATF1_100-6)

Comment: Existence of a reliable geologic barrier to vertical fluid migration is essential in creating storage permanence. We recommend that CARB require demonstration that a sequence of rocks will act as a confining system with the ability to secure CO_2 permanently.

The proposed Protocol requires that "[t]he storage complex must also include at least one overlying dissipation zone (dissipation interval) and at least one additional confining layer (secondary confining layer) to increase storage security and reduce other risks."[2]

[2] ATTACHMENT 1: CCS Protocol – A: Definitions and Applicability, Page 20/175.

The number of layers does not imply that a site is adequate from a security standpoint. Conversely, absence of an additional confining layers does not imply that a site is inadequate from a security standpoint. There could be several circumstances where one excellent confining layer provides greater security than two layers of a lesser quality. Such is the case for the flagship Sleipner CCS project in Norway, for example.

While the requirement for a secondary confining layer and dissipation interval is potentially useful in certain parts of California, the approach has the following fundamental flaws when utilized as a general global approach:

- Rock sequences are by their very nature heterogeneous. For example, in the San Joaquin Valley, the sands are fluvial in origin which means they may be laterally discontinuous (imagine an ancient meandering river) however robust they may look in a wellbore or core sample. The requirement to present three named layers may lead to inaccurate descriptions.
- Out-of-state projects qualifying under the LCFS will likely have very different geological settings, such as carbonate sequences where a pressure dissipation interval does not exist, yet the storage complex is demonstrably secure for permanent storage (e.g., reservoirs of the Permian Basin capped with salts).
- A pressure dissipation interval could be used as a primary storage reservoir given that, by definition, the interval must be overlain by a robust seal.

In addition, there appear to be conflicting definitions and requirements for the additional confining layer. The Definitions and Acronyms section[3] defines a confining layer as one that "impedes" the upward migration of fluids, whereas the Minimum Site Selection Criteria section[4] requires that the secondary confining layer be "impermeable".

[3] ATTACHMENT 1: CCS Protocol – A: Definitions and Applicability, Page 12/175.

[4] ATTACHMENT 1: CCS Protocol – C: Permanence, Page 44/175.

We recommend that CARB evaluate the potential advantages of, but not require, a secondary confining layer and dissipation interval for all projects, and instead require demonstrating that features specific to the site will reduce vertical leakage risk to acceptable levels using a geologic model and geomechanical and fluid flow data and calculations.

In addition to requiring both a primary and secondary confining layer (with an intervening dissipation layer), the proposed Protocol outlines specific rock test data and formulas for characterizing the primary confinement layer. Notable among these is the determination of rock strength and ductility by means of a brittleness index calculation (BRI), with the implication that a BRI number greater than 2 may be unacceptable in that "…discontinuities may be open." Recent literature in the unconventional resources space illustrate that a such simplifications are contentious.[5] In reality, fracture containment is predominantly controlled by stress contrast between the sequestration zone and the confining layer. In areas with some degree of tectonism, "brittle" layers can be less conducive to fracture propagation, because these layers also tend to be stiffer and have a higher stress. Thus it has been concluded that "…computing shale brittleness from elastic properties may not be physically meaningful."[6]

[5] Herwanger et al., 2015
[6] Vernek, 2012

Rather than evaluating confining layers based on specific petrophysical and geomechanical properties, the quality of the entire containment system should be considered. Current best practice now includes development of mechanical earth models (MEMs), which integrate the geology, material properties, pore pressure and tectonic loads to provide a more meaningful assessment of the integrity of the confinement system via prediction of stress under both pre- and post-injection conditions. This would obviate the need for secondary confining layers in some cases, and would probably increase the number of suitable storage venues (e.g., carbonates, marls, many Mesozoic and virtually all Paleozoic systems), some of which would certainly be eliminated if following the proposed criterion that is based on just a few experimentally-determined ratios.

It should also be considered that the status of a seal can change from being a membrane seal to a hydraulic resistance seal, the former being considered close to impermeable and the latter permitting a very low, but constant flux of fluid across a boundary until the pressure differential is resolved. The relationships between capillary entry pressure and threshold percolation pressure in relation to reservoir overpressure need to be clearly understood in order to adequately assign levels of risk. (CCSPD1_106-8)

> **Agency Response:** In response to these comments, staff changed the term "confining layer" to "confining system" in all instances of the term in the Protocol and revised the definition in subsection A.2.(a) to agree with the new use of terminology. Staff recognizes the need to distinguish among different geologic settings, and acknowledges the commenters' concern that the previous definition of "confining layer" placed restrictions on the minimum site selection criteria.

Confining system is now defined as *a multi-layered* laterally extensive geologic formation, group of formations, or part of a formation, stratigraphically overlying the sequestration zone that exhibits low permeability and/or high capillary entry-pressure (e.g. a clay-rich shale or mudstone) such that it impedes the upward migration of fluid(s). This definition addresses the commenters' concerns that specifying an exact stratigraphy is too limiting, yet maintains robustness and environmental integrity. The new definition is consistent with the original, but adds flexibility. The changes to the terminology and definition clarify the requirement for robust confinement of the CO_2 plume, and are consistent with the modifications made to the definition of "storage complex," which was addressed in Response M-2.1 in this chapter.

In regard to comment CATF1_100-6, staff agrees with the commenters' assertion that the original definitions of "confining layer" and "dissipation interval" were incongruent with the requirements of subsection C.2.1(a)(4) of the Protocol. Therefore, while staff kept the definition for "dissipation interval" unaltered, the requirement for a dissipation interval was removed from the minimum site requirements, along with the requirements for a primary confining layer, dissipation interval(s), and secondary confining layer(s). These were then replaced with the requirement for a *confining system composed of a layered interval of low and moderate permeability rocks* in subsection C.2.1.(a)(4). Staff believes that this change improves the Protocol by requiring a robust, multi-layer confining system comprised of multiple seals and/or dissipation intervals, yet allows for the inclusion of sites with demonstrably secure permanent storage capabilities that were previously eliminated due to the former approach to site selection.

In regard to the comment concerning the brittleness index requirement, staff does not agree that a brittleness index calculation is unproductive, or that evaluating confining layers based on specific petrophysical and geomechanical properties is unnecessary. First, besides helping to define risk, baseline limits on physical properties are essential components needed to define what it means to be a confining layer. Second, the Protocol was designed such that the quality of the entire containment system is of utmost importance. Removing requirements to describe, evaluate, and place limits on those petrophysical and geomechanical properties of seals is counter-productive to that goal. Therefore, staff did not alter the requirement for brittleness index calculations.

M-2.3. *Definition of "Plume Stability"*

Comment: We recommend that the plume be considered "stable" when injection has ended, and the rates of CO_2 migration and changes in pressure have decreased so that the risk of CO_2 migration out of the storage complex is calculated to be minimal with a very high degree of confidence. <u>Demonstration of stabilization should be accomplished by a combination of measurements within, as well as at the edges of, the plume, and a good match to a fluid flow model predicting long term fate of the CO_2. We also</u>

recommend that plume stability be defined explicitly in the Definitions section and not only by reference later in the document. (CCSPD1_106-7)

> **Agency Response:** Staff recognizes that the term "plume stabilization" was used in the Protocol, but never defined. Thus, in response to this comment, staff added the term "plume stabilization" to the definitions within the Protocol (subsection C.A.2(85)). Staff worked internally and with stakeholders to develop a reasonable and workable definition.

M-2.4. ***Definition of "Assets"***

Comment: In Section A.3(a)(5), the CCSP defines "Assets" to mean "all existing and all probable future economic benefits obtained or controlled by a particular entity." WSPA believes that including "all probable future economic benefits" in the definition is too speculative. A better definition would be: "a resource with economic value that an entity owns or controls with the expectation that it will provide future benefit." (WSPA3_93-8)

> **Agency Response:** Staff acknowledges the commenter's concern with the definition of "assets." CARB staff used internal legal and financial expertise to develop the definition, and feel that it is sufficient for its use in the Protocol.

M-2.5. ***Concern Regarding Multiple Definitions***

Comment: Descriptions for key attributes of a potential CCS project are conflicting, such as area of review (AOR) for example, causing confusion and uncertainty regarding CCS Protocol requirements. The AOR is initially defined in the Definitions and Acronyms section as the *lateral extent* or surface footprint of the pressure front at depth in the storage complex, with pressure front defined (similar to the EPA definition) as a region where the pressure rise is sufficient to lift formation fluids from the sequestration zone due to CO_2 injection. Further on in the CCS Protocol (Section 2.4.1) the AOR is referred to as *the lateral and vertical migration* of the *free-phase and dissolved* CO_2 plume and pressure front, as well as *formation fluids*. Later in the Specific Purpose and Rationale section (Attachment 2), it is stated that the "extent of the *dissolved and free-phase* CO_2 plume and pressure front" must be tracked. The AOR is further defined in this section as encompassing the *three-dimensional (3-D) region* of the pressure front, as well as the region overlying the *free-phase (i.e., not dissolved)* CO_2 plume. All definitions (e.g., AOR, CO_2 plume, storage complex, etc.) should, therefore, be sufficiently detailed in the Definitions and Acronyms section, with revisions to the remaining document to ensure further explanation does not contradict the description. (RTE1_36-5)

> **Agency Response:** Staff acknowledges the commenters' concerns regarding the inconsistencies with the definitions of terms such as "area of review." In order to address these concerns, staff revised the terms "area of review" and "storage complex" in subsection A.2.(a) of the Protocol during the 1st 15-day changes. In response to comments submitted during the 1st 15-day comment

period (see staff's response to comment CATFNRDC1_FF55-32 in Response M-2.3 in Chapter V), staff removed the term "area of review" altogether (also see Response M-2.1 in this chapter). Staff also replaced the term "pressure front" with "elevated pressure" in all instances of the term in the Protocol. Staff also paid careful attention to how each of these terms was used in the Protocol, and made corrections as applicable.

M-2.6. *Definition of "CO_2 Stream"*

Comment: The definition [of "CO_2 stream"] should recognize that there may be substances added to a CO_2 stream in the context of CO_2-EOR that are added to the stream to enable or improve the production of oil.

"CO_2 stream" means CO2 that has been captured from an emission source (e.g., a power plant), plus incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process <u>or EOR production</u>." (RFVV1_126-5)

> **Agency Response:** Staff does not agree with the commenter that the addition of "or EOR production" is necessary. The current definition in subsection A.2.(a) of the Protocol does not preclude additives for EOR production. Therefore, no change was made to the Protocol.

M-3. *General Comments on CCS and the CCS Protocol*

M-3.1. Multiple Comments: *Concerns Related to Costs and Technical Barriers to Implementation*

Comment: If approved as proposed, the Carbon Capture and Sequestration (CCS) Protocol would provide for a set of overly complex, onerous requirements that will likely create a barrier to implementation by conventional ethanol producers. With these regulatory barriers, along with significant capital investment and operational costs, it is unlikely that the staff estimated 1.4-7.2 million metric tons of CO2 sequestered in California, and elsewhere, by 2030 will be realistically achieved. (FHR1_18-6)

Comment: *4. In doing a scan of this document, I did not see anything obviously technically incorrect. But the amount of detailed instruction, reporting requirements and data submission is staggering. For example, it requires the approval of the Executive Director to change the location of a packer? If their intent is to stifle use of CCS to meet CARB requirements, then they have done a good job. One more thing.* (CSAG1_28-3)

Comment: In reviewing the CCS protocol as applied to the types of reservoirs in California that may serve as CO2 storage, CRC believes that the requirements of the protocol are overly prescriptive, restrictive and too expensive to implement and maintain, meaning that no such project would be built. We note that many of these burdens were identified in detail in the December 4, 2017 letter to staff by a broad consortium of experts including representatives of academia, industry (including CRC),

and non-governmental organizations. The letter can be accessed here: https://www.arb.ca.gov/fuels/lcfs/workshops/12042017_coalition.pdf (CRC1_35-2)

Comment: We respectfully request that the subject CCS Protocol continue to be discussed with stakeholders before formal adoption at this time. Ethanol fuel production integrated with CCS can help California ARB meet its new 2030 goals for significantly reduced carbon intensity (CI). However, the economic incentive via credits needs to be substantially greater than the potential costs that could be incurred to obtain an approved pathway that includes CCS; this is not the case under the current version of the CCS protocol. The most concerning topics to Red Trail Energy, LLC, are detailed below, with assistance from the Energy & Environmental Research Center based on expertise and experiences in commercial-scale CCS implementation. (RTE1_36-1)

Comment: The detailed, prescriptive requirements and frequent use of the term "must" is excessive, as well as economically challenging and restrictive to technological advancements. Examples for surface and near-surface monitoring include requirements of atmospheric monitoring, annual vegetation surveys, grid methodology, and baseline comparisons of all data. Atmospheric and vegetative monitoring in addition to soil/vadose zone monitoring is redundant and, possibly, ineffective. Fugitive emissions that are not detected in the soil will be too small to detect in the atmosphere, especially on a windy day. Vegetation can be highly unstable, particularly in arid climates as precipitation and temperatures are widely variable from year to year. Climate cycles in general can cause natural variation in any near-surface monitoring results, causing baseline comparisons to be misleading, and isotopic analyses do not require baseline results for comparison. Alternatively, use of a "grid methodology" is required for soil gas monitoring but explicitly not defined, merely stating a basis on "site-specific factors." The monitoring program as a whole could have this designation with desired metrics defined, such as basing frequency and techniques on outcomes of the performed risk assessment as opposed to prescribed requirements and baseline results.

Another example is the acceptable storage complex attributes. The requirement of "at least one overlying dissipation zone" with secondary confining layer is not a technical necessity for storage security and may negate an otherwise technically viable CCS project. It may also economically prohibit a potential CCS project, as securing rights to additional pore space could result in more complex negotiations and doubling payments (at minimum) to pore space owners. Similar to previous statements, site-specific evidence of secure storage complex could be designated instead with desired metrics further defined. (RTE1_36-4)

Comment: It is anticipated that California ARB will need help from out-of-state fuel producers to meet its new 2030 CI goals, which include ethanol integrated with CCS. CO_2 storage projects by nature are very site-specific, each with unique geology and infrastructure requirements for integration of CO_2 capture systems, whether a dedicated saline storage or EOR effort. Thus we recommend the CCS protocol be more flexible to incentivize out-of-state fuel producers to participate in the LCFS program and implement CCS in a proven manner for secure CO_2 storage. At minimum, a section or

language should be added that allows California ARB to negotiate with out-of-state CCS Project Operators and related authorities to provide accounting and permanence reporting and verification that satisfies LCFS objectives without violating other state and federal laws and primacy. (RTE1_36-7)

Comment: It is also critically important to ensure that the requirements associated with CCS-EOR are achievable and realistic such that actual projects can be developed. There are a number of technical issues CIPA is aware of and have been submitted in this rulemaking and by a coalition of experts including representatives of academia, industry (including CIPA members), and non-governmental organizations. CIPA request that CARB review the proposed CCS methodologies to ensure the requirements are not overly burdensome. These requirements include: limited injection and annual pressure requirements, 100-year post-injection operator monitoring, downhole seismic monitoring, monitoring the CO2 plume and plugging and abandonments. (CIPA1_71-8)

Comment: WSPA is concerned that key requirements of the CCSP have no technical basis. Requiring monitoring over unreasonable periods and requiring prescriptive elements which research and experience show will not provide relevant data introduces two areas of concern:

1. Such requirements will likely have a chilling effect on use of an important potential technology, which ARB's E3 study relies on to help the state reach its goals after 2030.
    - For example, the requirement that the "The CCS Project Operator must show proof of exclusive right to use the pore space in the sequestration zone for storing CO_2 permanently" may not be unobtainable but will be a major barrier to on-shore CCS.
    - Although Class VI may not be a perfect construct, it provides consistency nationwide for anyone that wants to do a project. Under the proposed protocol, project proponents would be faced with decisions whether to follow Class VI and the more onerous California Protocol. There is no technical basis for California to go beyond the Class VI program.
2. The data does not, in fact, provide the assurances that the state seeks and thereby misdirecting attention and resources away from valid approaches to monitor and evaluate CCS project success. (WSPA3_93-1)

Comment: While the notion of injecting CO_2 underground for the purposes of climate mitigation is relatively recent, the mechanics of it are not. Nature has been doing this for millions to hundreds of millions of years, and we should expect risks from the engineered aspects of geologic storage to be somewhat similar to oil field operations that California has conducted for a century.[1]

[1] Experience in Texas is that CO_2 operations fall within the same non-compliance ranges as other types of well failures. See Porse et al. 2014.

CARB's task at reconciling these objectives is particularly challenging. For this effort to be successful, several objectives need to be met. The rules need to be consistent with, and acceptable within CARB's regulatory framework. They need to safeguard public health and the environment, and the implementation of California's climate programs. They need to assure stakeholders and the public of the integrity of the program. Finally, they need to be workable in practice so a variety of real-world projects can utilize them and further the goal of emission reductions under California's climate goals. (CCSPD1_106-2)

Comment: However, the proposed CCS protocol is not in a useable form. Adopting the protocol as part of this rulemaking will not benefit the program and CARB should defer it to a later date and continue to work with stakeholders to refine the protocol.

Certain provisions of CARB's March 6, 2017 draft CCS regulations are likely to hinder CCS project development in California, thus substantially reducing the state's prospects for achieving its climate goals at an economic and environmental cost acceptable to its residents. Our concerns are detailed below. (CHEVRON1_112-13)

Comment: It is likely that getting a permit for CCS will take many years due to overlapping State and federal authorities and the complexity of projects.

And therefore, it is really important to complete a CCSQM before, in the next few years. (CHEVRON2_T33-2)

Comment: NextGen California **supports the inclusion of CCS pathways in the re-adopted LCFS**. Given the novelty, uncertainty and risk associated with this technology, we urge CARB to find an appropriate balance between supporting maximum deployment of this technology while protecting California, and the climate, from associated risks. We urge CARB to adopt a rigorous and transparent process for certifying CCS pathways and verifying that their real-world performance matches the on-paper claims. We recognize that CCS policies work on a time horizon which is quite different than most projects relevant to the production of transportation fuels; injection of CO_2 may occur over decades and post-injection monitoring should extend for at least a century, in order to match the common definition of "sequestered" carbon. Over these time scales, the technology used to sequester carbon and monitor completed projects will change significantly; a body of literature reflecting real-world experience will also emerge. CARB must design its CCS protocols with the understanding that we are only beginning to develop technical fluency in CCS. As such, current policies surrounding CCS should err on the side of risk-aversion, but acknowledge that change in regulatory, technical and monitoring practices are certain to occur. As we gain more experience with CCS operations, CARB can relax provisions which may turn out to be unnecessary. If a conservative near-term policy structure proves to be an impediment to deployment of the first generation of commercial projects, it would be better for CARB to support a set of pilot projects through a process unconnected to the LCFS program than to establish pathways under the LCFS that incentivize deployment of unnecessarily risky projects. (NEXTGEN1_124-25)

Agency Response: Staff believes the stringency level is appropriate to ensure proper site selection and site care that results in permanent sequestration as required by AB 32. Staff believes the Protocol ensures only geologically appropriate and well managed sites will be able to comply, and those sites should be able to meet the requirements. During the development of the CCS Protocol, CARB staff collaborated with stakeholders from industry, academia, non-governmental organizations, and regulatory agencies, with the intention of striking the right balance to ensure real, safe and permanent sequestration and develop a workable Protocol.

In response to stakeholder feedback, staff worked to replace prescriptive requirements with performance-based provisions that allow the use of equivalent or better technology, where appropriate and feasible. Staff also revised provisions to ensure that site-specific requirements based on project-specific risk were incorporated, when appropriate. Staff has proposed minimum requirements for criteria in which industry-accepted standards must be met to ensure permanent CO_2 sequestration. Specific comments related to technical concerns are addressed elsewhere.

Staff does not agree that the Protocol should be withheld from the LCFS rulemaking package at this time. As noted in other stakeholder comments (see, for example, comments NRDC1_81-16 and CCSPD1_106-4), the Protocol is robust and comprehensive, providing necessary safeguards as we develop the first projects to receive credits in the program.

The Protocol was developed over the past several years, staff has hosted six technical discussion sessions, four workshops, and held numerous stakeholder meetings on CCS; staff will continue to welcome comments and suggestions from stakeholders and make subsequent adjustments as necessary.

In regard to comment WSPA3_93-1 concerning the US EPA's Class VI rule, the Protocol is consistent with the rule, but goes above and beyond those requirements as necessary to ensure real and permanent reductions. Many of the requirements of the Protocol are also requirements necessary to obtain a Class VI permit, and CCS projects should be designed to meet both. Furthermore, the purpose of the U.S. EPA Class VI well rule is to protect drinking water resources. Whereas the purpose of the CCS Protocol is to ensure GHG reductions are permanent. By following the requirements of the Protocol, regulated entities can receive credit under the LCFS. The Protocol is one of several tools entities may use to comply with the LCFS; the Protocol is not the *only* tool entities must use to comply. Entities may also choose to use the Class VI rule to apply for the Federal 45Q tax credit, thereby opting out of the LCFS.

It follows, then, that staff also disagrees with commenters' concerns regarding the compliance cost of the CCS Protocol. In addition to the costs of existing federal and state regulations, the compliance costs for the CCS Protocol are related to monitoring, liability, and those set aside for potential future remediation

activities. For CCS projects that are high-quality with well-characterized sequestration sites, staff expects these additional costs to be minimal when compared to the potential benefits.

Regarding the comments about pore space right-of-use (comments RTE1_36-4 and WSPA3_93-1), staff maintains that the requirement for operators to obtain exclusive rights to the pore space of the sequestration zone is an essential component of Permanence Certification, and a demonstrable step operators can take to show that they are committed to ensuring permanence. Maintaining the integrity of the sequestration zone is of the utmost importance to CARB, and therefore, if operators wish to participate in the LCFS via CCS, they will need to perform the necessary due diligence to CARB's satisfaction. Thus, staff made no modifications to the Protocol as a result of these comments.

For discussion concerning other issues raised in these comments, please refer to the following table:

Response	**Topic**
Responses M-3.2 and M-13.2	Prescriptive requirements and performance-based methods
Response M-6	100-year monitoring requirement
Responses M-13.3, M-13.4, and M-13.5	Well plugging and abandonment
Response M-15	Baseline surface and near-surface monitoring
Response M-16	Injection pressure restrictions
Response M-17.1	Annular pressure monitoring
Response M-17.5	Downhole seismicity monitoring
Response M-17.6	Monitoring the CO_2 plume

All responses listed above are found in this chapter.

M-3.2. Multiple Comments: *Using a Performance-Based Approach*

Comment: I. A Performance-Based Approach Will Provide Better Long-Term Storage Security.

A performance-based approach is necessary to secure subsurface storage of carbon dioxide (CO_2) in saline projects and will provide the added benefit of better integrating the requirements in the Protocol for use in commercial enhanced oil recovery (EOR)

projects. Monitoring, in general, should be designed to detect leakage in a wide range of geologic project environments, some of which could be outside of the State of California.

In a performance-based approach, project operators build a model of the storage complex, identify areas of potential leakage risk, and tailor the monitoring plan to the risk model and local geology. A performance-based approach will enable operators and CARB to effectively determine, for each different project, what combination of performance criteria and monitoring will provide a sufficient level of certainty that CO_2 will be securely stored over the 100-year permanence period and well beyond. In the case of EOR, monitoring data may include CO_2 conformance metrics already in use by the project. The plan should describe the detection process, and the effective threshold at which leakage from any possible pathway from reservoir to surface will be detected. This would include a detailed explanation (using maps and modeling) of what measurement and modeling steps will be used to trigger a finding of leakage detection. The plan should explain in detail the process by which leakage will be verified, quantified, and mitigated, and if mitigated how the mitigation will be validated, including the accuracy and precision of the methods utilized. Dr. Hovorka has submitted some suggested changes to the Protocol, accompanied by our letter of support, which we believe will help make it more performance based. (CATF1_100-2)

Comment: CATF strongly supports the inclusion of CCS within the LCFS regulation. The proposed Protocol requires all projects, irrespective of storage site characteristics or risk profile, to perform post-injection field monitoring for a minimum of 100 years to demonstrate permanent sequestration of CO_2. The Protocol defines "Permanent sequestration" or "permanence," to mean that "sequestered CO_2 will remain within the storage complex for at least 100 years"[5] Regarding the issue of permanence, CATF would emphasize that in order to reverse climate change, CO_2 that is captured and stored must remain sequestered permanently for much longer timeframes than 100 years. On post-injection monitoring requirements, CATF proposes that CARB develop a performance-based approach that will support the development and operation of CCS projects that will ensure secure sequestration of CO_2 on a geological time scale.

[5] California Air Resources Board, Appendix B – Attachment 1: Carbon Capture And Sequestration Protocol Under The Low Carbon Fuel Standard, at page 17, *available at:* https://www.arb.ca.gov/regact/2018/lcfs18/appb.pdf

In a performance-based approach, storage security is a function of the quality of the geologic storage site, which is a product of the site selection process, the design of the injection, and the tailoring the monitoring and verification methods to the leakage vulnerabilities, using tools that can detect CO_2 in the project environment over the desired timeframe. For the practical purposes of accounting, demonstrating that stored CO_2 has achieved an equilibrium state with the host rock, such that it will not migrate out of the prequalified volume defined as the storage complex, is the goal of the Protocol. For storage in the deep subsurface, monitoring at the surface for 100 years has minimal value. Demonstration of permanence can be accomplished with highest

certainty by combining analyzed plume monitoring data collected in the subsurface, and using matched models to demonstrate a robust trend in CO_2 stability.

The proposed method of post injection monitoring using CO_2 concentration in the soil gas is not reliable. Robust scientific research on the ability of baseline soil gas methods to detect leakage, suggests that the use of soil gas monitoring is fraught with uncertainty. In some cases of known leakage, nothing is detected in the soil; in other cases an observed change in CO_2 concentration is related to the ecosystem and unrelated to the injected CO_2. Furthermore, location and placement of instrumentation is tricky and must be designed to monitor areas with best chance of detection. As an example, at Aliso Canyon, leakage from the subsurface blowout manifested itself at the surface at a distance from the wellhead, at the bottom of the hillside, such that a monitor near the wellhead may have not detected the blow-out early. Critically, if leakage is detected in soils it is too late to mitigate; whereas subsurface detection methods would in many cases allow prevention of significant leakage.

In CATF's comments,[6] submitted on February 1, 2018, we provide legal reasons for why 100 years of monitoring required in the forest offset protocol *does not* necessitate requiring comparable monitoring techniques and methods under the CCS protocol. Permanence in geologic settings is fundamentally different than the timber harvesting risk in forestry. CO_2 stored in mile-deep reservoirs is covered by a thick overburden of rock, typically very impermeable. Vertical migration, if pathways are present, other than through well penetrations, will take much longer timeframes. Failing to recognize these differences and failing to tailor the Protocol to the factors relevant to geologic sequestration would be unreasonable and does not fulfill CARB's fundamental objective of sequestration permanence.[7]

[6] Clean Air Task Force (CATF), Stakeholder letter in response to LCFS workshop Nov. 6, 2018 (Feb. 1, 2018), *available at:* https://www.arb.ca.gov/fuels/lcfs/workshops/02012018_catf.pdf.

[7] *Comms. for a Better Env't v. Cal. Resources Agency*, 103 Cal. App. 4th 98, 109 (2002)

This being said, and despite our objection to what we view as some overly rigid 100 year monitoring requirements, we have endeavored in our comments and proposed language to make judicious recommendations to make the rule more performance-based, within the confines of the 100 year requirement. If CARB wishes to retain the 100-year post injection monitoring requirement in the Protocol then CATF would urge CARB to make changes to the regulatory language as described below that preserve CARB's authority to impose various conditions but lessen the list of mandatory monitoring provisions applicable to all projects. The specific changes have been added as redline comments in Appendix A.

Our recommendations introduce several additional rule components that will facilitate the development of the most technically sound CCS projects and reduce obligatory monitoring not tailored to the risk profile of a particular project. We are confident that these approaches will enable performance-based monitoring and financial responsibilities throughout the life of CCS projects and the permanence period.

1. We recommend authorizing the complete transfer of project responsibilities including the Permanence Certification from a project operator to a third-party

subject to Executive Officer approval. *See* redline recommendation in section C.1.2 in Appendix A. Long term, public entities will likely be established to manage carbon sequestration sites in the most secure and efficient manner given the strategies and technologies available in the future.

2. The Protocol should more clearly delineate the responsibilities for the different phases of the project. The current protocol contains a section on Injection Monitoring Requirements at C.4 but the Testing and Monitoring provision expands the scope of testing and monitoring requirements under this section to the "post-injection site care period" at C.4.1(a). We recommend removing this ambiguity by more clearly limiting this Testing and Monitoring provision at C.4.1(a) to the "active life of the CCS project" which is the injection period. *See* redline in Appendix A.
3. Post-injection monitoring obligations are best addressed in the section entitled Post-Injection Site Care and Site Closure at C.5.2. The Protocol already requires and enables a thorough review of the Post-Injection Site Care and Site Closure Plan under C.5.3. This comprehensive review should be based on the best available science at the time of the review, and would reference the project's historical performance including regulatory compliance, technical performance, and all other project components. At the conclusion of the review, the Post-Injection Site Care and Site Closure Plan will establish the monitoring obligations and financial responsibilities of the project for the remainder of the 100-year period. Our recommended changes to C.5.2(b) (Post-injection site care and monitoring) have been crafted to empower the Executive Officer with full authority to impose all necessary obligations to ensure permanence but also to enable the Executive Officer to not be required to impose standardized monitoring on all projects. *See* redline in Appendix A. (CATF1_100-7b)

Comment: In conclusion, CATF urges CARB to more broadly implement a performance-based monitoring approach and to integrate the other specific recommendations we have submitted to the record. Our recommendation aligns with the California Legislature's direction to "substitute[e] performance standards for prescriptive standards wherever performance standards can be reasonably expected to be as effective and less burdensome."[8]

[8] CA Govt. Code § 11340.1(a).

We look forward to continuing our work with CARB on the Protocol and appreciate the ongoing opportunity to provide feedback and recommendations. We also look forward to the development of CCS projects that meet the final Protocol's requirements, and to the continued refinement of the regulatory structure based on real world experience, science and technology. (CATF1_100-9)

Comment: Briefly, we are advocating that CARB adopt a performance-based approach, which will add more certainty and security to the stored CO_2. In a performance-based approach, site selection, monitoring and verification requirements are tailored to local geology and conditions, and the verification plans are expected to be fit for purpose rather than being rigid.

…

We recommend making more parts of the CCS protocol performance-based and structured to leverage technological and scientific advances as well as project experience. (CATF2_B14-2)

Comment: Our recommendation is mainly that CARB adopt a performance-based approach, which will add more certainty and security to the storage of CO2. In a performance-based approach, monitoring and verification requirements are tailored to the local geology and local conditions; and verification plans are made fit for purpose rather than being rigid.

We appreciate some of the measures that CARB has already taken in the early rounds of drafts to make this protocol more performance based. This will ensure that the most secure and the best projects are implemented.

…

We just make -- we just recommend that CARB make more parts performance based and structured in such a way that it can leverage technological and scientific advances as well as project experience. (CATF3_T41-2)

Comment: Also in that plan is a pathway for ceasing monitoring reporting, which I'd like to talk to you about as maybe an alternative to include as part of your CCS standard.

So the plan, which again EPA approved, uses a sophisticated model that we developed for operation, and it's truth tested by real monitoring data over a period of years. And at EPA's discretion, they can determine when reporting should cease. So this performance-based approach we think might be a good additional option to include in the CC -- in your CCS protocol. (OCCIDENTAL2_T7-3)

Comment: We are supportive -- also very supportive of the inclusion of the CCS concept and would echo the more technical comments about making sure that the program is performance based and workable. (PE1_T42-2)

> **Agency Response:** During the development of the Protocol, staff made every effort to include performance-based requirements (see, for example, comment CATFNRDC1_FF55-24, Response M-1 in Chapter V). Many of the requirements in the CCS Protocol are site specific, where appropriate, and based on a risk-analysis of the specific project. However, staff has proposed minimum requirements for certain criteria that we see as generally accepted standards necessary to ensure permanent CO_2 sequestration.
>
> In response to comment CATF1_100-7b, concerning the responsibilities for different project phases, staff agrees with the commenter in that adding the phrase, “during the active life of the CCS project” clarifies that the testing and monitoring referenced in subsection C.4.1 is that which should take place during the active operational phase of the project.

In regard to comment CATF1_100-7b concerning the transfer of Permanence Certification, staff does not agree that any transfer of project responsibilities or certifications to public entities should be allowed. CCS projects have the potential to generate significant numbers of LCFS credits, while the remediation for a possible leak could be very costly and require retirement of many credits. Staff believes that the liability for each CCS project should remain with the operator who receives credits, and that the responsibility for the management of carbon sequestration sites should remain with that operator for up to 50 years post-injection (see Response M-6 in this chapter for further discussion of the liability timeframe).

See Response M-13.2 in this chapter concerning the suggested edits to Protocol subsection C.5.2(b), as referenced in comment CATF1_1007b, recommendation 3.

See Response M-6 in this chapter concerning the 100-year monitoring requirement.

See Response M-15 in this chapter for staff's response concerning soil gas monitoring methods.

M-3.3. Multiple Comments: *Out-of-State Storage Projects*

Comment: Not only is the current CCS Protocol more stringent for CCS systems than other fuel production systems, it is also significantly more severe than established state and federal requirements and is in direct opposition to existing laws in some other states. The U.S. Environmental Protection agency (EPA) has implemented Underground Injection Control (UIC) Class VI rules for dedicated storage; Class II rules apply to associated storage (e.g. enhanced oil recovery [EOR]). For and individual state to obtain primary enforcement authority or primacy, the application must provide evidence of developed programs at least as stringent as EPA's rules. Most states have Class II Primacy. North Dakota is the first state to have obtained Class VI Primacy (April 2018[1]), and Wyoming applied in January 2018. Clarification should, therefore, be added to address how California ARB will work through these challenges for ***out-of-state*** CCS Project Operators. Example language: *Programmatic changes may be proposed by out-of-state CCS Project Operators seeking pathway approval that is mutually agreed upon by the Executive Officer with site-specific evidence that the proposed program is equally secure and environmentally protective.*

[1] www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program.

(RTE1_36-2b)

Comment: CCSP, as written, establishes identical requirements for CCS operations that take place outside of California well as in state. While we support rules that establish a common outcome – the secure long-term storage of CO_2 - regardless of location, regulatory requirements in an out-of-state jurisdiction may not allow for identical practices. WSPA is concerned that a strict, to-the-letter interpretation of the permanence terms in the protocol would preclude any CCS projects undertaken outside

of California, where regulatory and legal frameworks may impose different terms and requirements.

WSPA recommends that ARB recognize out-of-state jurisdiction rules that deliver functionally equivalent outcomes to California's rules, such as jurisdictions where site closure rules are different and/or liability is transferred to the state, following ARB's protocol may not be possible. In such a case, the operator should be able to demonstrate the risk of leakage to atmosphere or to a connected water column has been reduced to a sufficiently low level to satisfy California's permanence criteria. (WSPA3_93-4)

Comment: CARB's protocol, as written, establishes identical requirements for CCS operations that take place outside of California as in state. While we support rules that establish a common outcome - the secure long-term storage of CO_2 - regardless of location, regulatory requirements in out-of-state jurisdiction may not allow for identical practices.

For example, would ARB require post-closure monitoring beyond the duration allowed by another local government? Would operators always be required to follow a different monitoring program than that which may already be locally mandated and enforceable elsewhere? Would ARB impose different bonding requirements on these out-of-state projects? Would the Protocol mandate different well maintenance activities, changes to operating procedures, or approval of site selection that may conflict with requirements that are subject to local regulation and approval elsewhere? In some, or likely many, cases, specific requirements in California's Protocols will have an analogue in another local jurisdiction, each with the intent of ensuring safe, permanent storage of CO_2. In other cases, they may not have an analogue, or they may not be as stringent as California's requirements.

<u>ARB should follow an approach that allows for functional equivalence to be the criterion by which the sufficiency of requirements from other jurisdictions are evaluated. Specifically, we recommend that the Protocol, through a new (sub)section, provide the Executive Officer with the option to accept certain requirements, data sources, methods or techniques from other jurisdictions in lieu of any relevant specific requirements in the Protocol, provided these offer an equivalent or better level of assurance in permanence than the requirements in the Protocol, and provided there is a demonstrated conflict between CARB's requirements and those of the other jurisdiction.</u>

We want to emphasize that we are not advocating for more lenient or favorable treatment for projects in other jurisdictions. We simply want to ensure that projects also governed by other requirements, or that use practices that are equivalent or better than those that would qualify under the Protocol, are not excluded from eligibility due to inconsequential mismatches in those requirements or practices. (CCSPD1_106-20)

Comment: Second, it seems the rule as written could try to impose California requirements on crude and fuel produced outside the state in a way that would be

unhelpful to the cause of growing CCS at scale. We look forward to working with staff and successfully addressing these concerns. (SHELL1_T50-7)

Agency Response: Staff appreciates commenters' feedback on the coordination of the requirements among different jurisdictions, but CARB staff has already aligned the Protocol with other requirements where it was feasible without undermining the integrity of the Protocol.

Staff did not include any provisions to allow CCS operators to apply for the LCFS program using projects that rely solely on U.S. EPA Class II or Class VI rules. Staff focused on developing a state-of-the-science, rigorous program that aligns with the high standards of CARB's existing climate programs. As a consequence, many of the Protocol's requirements are stricter than comparable regulations at the federal or regional level. Where appropriate or necessary, staff adjusted requirements to allow for the evaluation and substitution of other jurisdictional rules, provided they offer an equivalent or better level of assurance in permanence than the provisions in the Protocol. See subsection C.1.1.1(e) and (f) of the Protocol for examples.

The primary purpose of the U.S. EPA Class II and VI well rules are to protect underground drinking water resources. Whereas the purpose of the CCS Protocol is to ensure GHG reductions are permanent. As such, the CCS Protocol was developed to be consistent with CARB's climate programs in general, and to serve the needs of the LCFS program. For these reasons, the CCS Protocol may have requirements beyond the U.S. EPA Class II and VI rules, but the CCS Protocol is fundamentally compatible with the U.S. EPA rules.

M-3.4. *Offshore CCS Projects*

Comment: *They have limited the CCS to onshore applications, possibly to avoid legal issues? In any case, the Sleipner CCS project run by Norway in the North Sea is one of the most successful and long term CCS projects in the world. It seems very limiting to exclude CO2 storage in offshore oil fields, given California's resources in that area.* (CSAG1_28-4)

Agency Response: Given the available time and resources, staff was unable to complete a comprehensive review and analysis regarding offshore CCS projects. Including offshore reservoirs in the scope of the CCS protocol would require further engagement with stakeholders, as well as internal research and review of methods and standards. Staff will continue to study this subject and consider whether to update the Protocol to include offshore CCS projects in future updates if determined appropriate.

M-3.5. ***Citations***

Comment:

1. *I find it superb. The only critical comment I'd make is that there is no citation of prior standards on CCS or sources; e.g. no references to ISO nor to CSA. There are passing references to API and ASTM, of the nature "if it's OK with API it's OK with us."*

2. I realize that these are regs, not standards nor best practices, and there is no specific responsibility to cite sources. But the regs are sure to be challenged in court, and in my opinion they would be on firmer ground if they did not appear to come out of thin air. There is clearly a lot of work behind this. (CSAG1_28-1)

> **Agency Response:** Staff acknowledges the foundation of research behind the proposed CCS Protocol. In developing the Protocol, staff conducted an extensive review of previous standards and resources, including the work that has been done by Canadian Standards Association (CSA Group). However, staff intends to only refer to standards or resources that provide specific provisions that are necessary to ensure safe and permanent sequestration of CO_2, but that are not explicitly stated in the proposed CCS protocol.

M-3.6. ***Submission of Tabular Data***

Comment: Certain provisions in the proposed Protocol require that tabular data of all measurements of a certain type be submitted on a regular basis. We support the retention of records so that essential functions such as history matching and attribution of events be possible. <u>However, we recommend that CARB examine the feasibility and usefulness of submitting very large volumes of raw data in tabular form each applicable period.</u> For real-time measurements on a large number of wells, this could amount to a substantial paper submission. <u>Maintenance of appropriate records in the right format and ability by CARB to access those would be a more practical solution.</u> (CCSPD1_106-14)

> **Agency Response:** Staff acknowledges the commenter's concern with the submission of large amounts of tabular data, however, staff does not agree that any changes to the Protocol are required at this time.

M-3.7. ***Mitigation Plan***

Comment: In Table 2, a Mitigation Plan is required to address substantial and catastrophic risks that are possible and catastrophic risks that are unlikely. This is the only place in the document where the phrase "Mitigation Plan" appears. <u>CARB should clarify if it is receptive to the use of best management practices, or refer to established guidance.</u> (CCSPD1_106-32)

> **Agency Response:** The requirement for a "Mitigation Plan" comes from a previous version of the Protocol that was meant to be updated before the release

on March 6, 2018. Staff removed the requirement for a "mitigation plan" and updated Table 2 accordingly. Risk scenarios were added and reclassified to low, medium, or high, depending on the probability of occurrence or severity of potential consequences.

M-3.8. ***Potential for Widespread Deployment of CCS***

Comment: There is potential for significantly more deployment of CCS than just these applications, however. Post-combustion capture, in which CO_2 is scrubbed from normal combustion exhaust, may also be possible at costs below the expected combination of LCFS credits and 45 (Q) tax credits. This method of capture is potentially applicable to almost any large-scale stationary combustion process including power plants, refineries and biofuel production facilities. If post-combustion capture is widely deployed at all possible points in the transportation system, there could be the potential for tens of millions of tonnes of total LCFS credit generation per year. This would necessitate a fundamental re-examination of California's climate and energy policies. If post-combustion capture deploys widely, CI targets in excess of 30% may be required to ensure that the LCFS market stays strong enough to support alternatives to petroleum. While we feel commercial deployment of post-combustion CCS before 2030 is unlikely to occur at scales sufficient to necessitate such a re-examination, we urge CARB to monitor this technology closely and be prepared to take action. (NEXTGEN1_124-31)

Agency Response: Staff acknowledges the commenter's thoughts on LCFS credits and CI targets in relation to CCS. Post-combustion capture at LCFS related sources is allowed under the Protocol. However, additional sources and policies are beyond the scope of the CCS Protocol and of the current rulemaking. Staff will continue to monitor CO_2 capture technology, and looks forward to working with stakeholders on these topics in the future.

M-3.9. ***Use of Federal Permanence Requirements for Geologic Sequestration***

Comment: *CARB should modify the Permanence Requirements for Geologic Sequestration by requiring CCS Project Operators to solely meet the USEPA Underground Injection Control (UIC) Class VI rule requirements.*

On December 10, 2010, USEPA issued federal requirements under the Safe Drinking Water Act (SDWA) UIC Program for carbon dioxide geologic sequestration within a new well class, Class VI (see 76 FR 56982). This rulemaking established the minimum technical criteria to protect underground sources of drinking water from the long-term storage of carbon dioxide, including:

- Permitting
  - Geologic site characterization
  - Area of review (AOR) and corrective action
  - Financial responsibility

- Well construction
- Operation
    - Mechanical integrity testing (MIT)
    - Monitoring
- Well plugging
- Post-injection site care (PISC)
- Site closure

We believe that these federal requirements substantially meet the proposed Permanence Requirements for geologic CO2 sequestration and equally safeguard the potential risk of CO2 emissions downstream of the sequestration site. (FHR1_18-8)

> **Agency Response:** Staff does not agree with the commenter's assertion that the U.S. EPA Class VI rule is sufficient to meet the requirements of the CCS Protocol, or CARB's requirements to participate in our market-based carbon programs. Please see Response M-3.1 in this chapter regarding the Class VI rule versus the CCS Protocol.

M-4. Multiple Comments: *Commentary Accompanying Technical Recommendations*

Comment: I have reviewed these line edits and accompanying comments, provided suggestions, and it is my expert opinion that the revisions proposed by Dr. Hovorka strengthen and improve the CARB Proposed Protocol by application of advanced scientific research knowledge to optimize storage facility project design, enable effective CARB oversight, and thereby maximize the security and permanence of sequestered CO_2. CATF therefore joins Dr. Hovorka in the submission of these comments and strongly endorses the integration of the line edits into the CARB Proposed Protocol. (GCCC1_14-2)

Comment: Please note that CATF will also be submitting comments and proposed language to the Board regarding other opportunities to enhance the effectiveness of the 100-year requirements in the CARB Proposed Protocol and to tailor these requirements to enable sound CCS project development. These issues are not reflected in the attached redline. (GCCC1_14-3)

Comment: I am also influenced by drafts of standards for CCS under the leaderships of the International Standards Organization; in preparation of these drafts many stakeholders have discussed accounting protocols over the last few years. My technical comments are also based on global collaboration with research in geologic storage gained through meetings, workshops, publications, technical reviews, and joint research; I believe that most of my comments are aligned with best current knowledge of practitioners and technical experts. (GCCC1_14-5)

Comment: I have not considered policy aspects of the protocol but focused on technical recommendations to meet the goals already set forth. If I was to undertake a review of goals I would recommend streamlining the requirements to focus on activities that lead to the new elements of rigorous and transparent accounting for storage. Other issues that are addresses by federal or state UIC rules might be linked more cleanly to these rules by citation. However such major revisions may not be practical at this point in the decision-making or meet CARB's goals. (GCCC1_14-6)

Comment: In addition, I have recommended a number of other revisions to the CCS Protocol, some of which are simply directed at correcting errors in language that have persisted in the document and need to be corrected. Other recommendations are designed to improve the CCS protocol while preserving its effectiveness. (RFVV1_126-3)

Comment: Our other technical recommendations will help the Protocol become broader and provide more certainty for CO_2 storage in depleted oil fields, making storage more secure. (CATF2_B14-3)

Comment: Our other technical recommendations will help the protocol become broader and provide more certainty for storage in depleted oil fields, making storage more secure. (CATF3_T41-3)

> **Agency Response:** Staff appreciates the commenters' expertise and thoroughness in regard to their review of the CCS Protocol, as well as their insight and commitment to CCS as a whole. Staff acknowledges the specific recommendations associated with the line edits, which are responded to elsewhere in Responses M-5.1 and M-5.2 in this chapter.
>
> In regard to comment GCCC1_14-2, staff thanks the commenter for their review of the line edits to the Protocol submitted in comment letter GCCC1_14.
>
> In regard to comment GCCC1_14-3, staff acknowledges the commenter's submittal of a separate comment letter concerning the 100-year monitoring requirement. Please see Response M-6 in this chapter.

M-5. Multiple Comments: *Editorial Comments and Suggested Line-Edit Revisions*

CARB received multiple letters that included line edits of the CCS protocol with strike out and underline suggestions. The following sections (M-5.1, M-5.2, and M-5.3) are responses to those line edits. All the comments listed in M-5.1 were accepted in whole. The comments in M-5.2 were accepted except where noted in the response. The comments in M-5.3 were not accepted.

The following sections (M-5.1, M-5.2, and M-5.3) are organized differently than the rest of the document. The comments start with a comment that was provided by the commenter as a comment bubble in the document, followed by the suggested line-edit revisions indicated in quotes and in underline-strikeout format.

M-5.1. Multiple Comments: ***Comments that Informed Revisions to the Protocol***

Comment: Avoid technical issues with term "pressure front". See " Oldenburg, CM; Cihan, A; Zhou, QL; Fairweather,; Spangler, LH. GREENHOUSE GASES-SCIENCE AND TECHNOLOGY Vol: 6 Issue: 6 Pages: 775-786 DOI: 10.1002/ghg.1607 DEC 2016

"…~~the~~ elevated pressure ~~front~~ at…" (GCCC1_14-9)

Comment: Lateral migration out of the storage complex also can result in significant losses. Or specify lateral or vertical migration

"…and ~~above~~ out of the storage complex…" (GCCC1_14-10)

Comment: Definition (95) correctly defines recycle. Separation is used and not defined

"'CO_2 ~~recycling~~ separation'…" (GCCC1_14-11)

Comment: A layer with three layers within it is confusing

More than one layer

The whole confining system is part of the Storage complex

"'Confining ~~layer~~ system' means a multi-layered…" (GCCC1_14-12)

Comment: Need the three dimensional volume, not the surface outline.

Need the three dimensional volume, not the surface outline.

The 3-D volume should be evaluated for mineral deposits (e.g. mines or resource extraction at depth)

Need to make sure that the 3-D data are called for.

redundant

This needs to be relevant to the 3-D volume, For example, it should include deviated wells that enter the storage complex underground. It does not need to include wells that produce from or inject into zones that are above the storage complex

AoR replaced throughout document because, three-D geometry is critical. Operator does not need to remediate water wells or injectors or producer into shallower zones.

Include deviated wells that are not in AoR that come into storage complex

"storage complex" reflects the 3 dimensional volume" rather than the surface area in the term "AoR".

"…~~an AOR~~ a storage complex…" (GCCC1_14-13)

Comment: "Can be used for monitoring" (GCCC1_14-14)

Comment: Historic surveys should be acceptable also

"…~~using a global positioning system~~…" (GCCC1_14-15)

Comment: Interpretation is required

"…~~dictate~~ in interpreted to set…" (GCCC1_14-16)

Comment: Total mass

"…and fluid…" (GCCC1_14-17)

Comment: Various types of completion can be used

Various types of completion can be used

"'~~Perforation~~ Completion interval'…" (GCCC1_14-18)

Comment: Definition needed for storage complex definition and for closure discussions.

"'Plume stabilit~~y~~zation" means that plume migration and pressure changes are small and predictable and the risk of migration outside of the area of review is reduced." (GCCC1_14-19)

Comment: "…~~of~~between crystals or grains in a rock…~~voids~~…" (GCCC1_14-20)

Comment: [Applies to comments 14-20 and 14-21] These two definitions should work together

"…~~the void~~ pore space ~~in the rock that is not occupied by solid grains or minerals. The space between crystals or grains in a rock that is available to be filled with a fluid such as water, oil, or gas, is called 'pore space.'~~" (GCCC1_14-21)

Comment: EPA's pressure front has technical problems that should be avoided. See Oldenburg paper cited above.

Pressure is usually a key model matching parameter

Elevated pressure should be reported over storage complex, not just a "front". During closure, the pressure should decline, this decline should be documented.

"'Elevated ~~P~~pressure ~~front~~' means ~~the region surrounding~~ fluid response to CO_2 injection ~~wells in which~~ such that the pressure rise ~~is~~ creates leakage risk. ~~sufficient to~~

~~lift formation fluids from the sequestration zone, above the storage complex.~~" (GCCC1_14-22)

Comment: A performance-based definition is stronger and more realistic than prescribing a three-layer system. See real cases of confinement for storage.

"…multilayered confining system … ~~(confining layer or primary confining layer). The storage complex must also include at least one overlying dissipation zone (dissipation interval) and at least one additional confining layer (secondary confining layer) to increase storage security and reduce other risks.~~" (GCCC1_14-24)

Comment: Characterization and qualification of the storage complex over the ultimate plume extent is important.

"…~~associate pressure front~~ area over which the plume may migrate prior to stabilization." (GCCC1_14-25)

Comment: Edits for clarity

"…~~such~~ as defined by…~~image~~ volume." (GCCC1_14-26)

Comment: In EOR the measurement location should be optimized to avoid measurement complications from recycled CO2, which is not pure.

"…~~at~~ before…" (GCCC1_14-29)

Comment: Error may come from the analytic approximations.

"…~~equipment~~ method…deployed…and testing…" (GCCC1_14-31)

Comment: This line ["…using a method identified in the project's monitoring and testing plan."] is a key phrase that should drive specifics of the monitoring and testing plan. (GCCC1_14-32)

Comment: Storage complex is the defined term for authorized storage

"…migrates outside the storage complex or…~~or other unauthorized zone~~." (GCCC1_14-33)

Comment: These data should be reported.

"…report…" (GCCC1_14-34)

Comment: ARB should require a report detailing the decisions made in the model development. The report should be available at the time of application because the AOR and storage complex should be fully defined in the application.

"…report on the results of the ~~AOR~~ plume evolution ~~delineation~~…" (GCCC1_14-35)

Comment: The results could include:

1) Plume is within storage complex at time of report;
2) Updated model (adding in last 5 years of monitoring data) is predicted to remain inside storage complex at stabilization;
3) If part of the Plume is has migrated out of storage complex at time of report, and effective permanence can no longer be demonstrated. a reversal of storage credits is made;
4) If part of the Plume is has migrated out of storage complex at time of report, however, additional documentation has been provided to show that the plume will be effectively stored in a new/revised storage volume, an extension of the storage complex will be requested;
5) If the updated model is predicted to leave the storage complex before stabilization, option #3 and # 6 (above) an be actions or;
6) The injection operations can be modified and the updated model rerun, showing that under updated conditions the plume is predicted to remain inside storage complex at stabilization.

"…plume location ~~AOR~~ reevaluation and actions resulting from this finding…" (GCCC1_14-36)

Comment: Two layers is geologically simplistic and not likely to match most subsurface conditions. We recommend that the operator be required to make a demonstration to the satisfaction of the director of a robust confining system that has demonstrated geologic features and capacity to contain CO_2 permanently.

"A ~~minimum of one additional permeable stratum[6] (dissipation interval) situated directly above the sequestration zone and confining layer, with at least one impermeable confining layer (secondary confining layer) between the surface and the dissipation interval. The sequestration zone, primary confining layer, and dissipation interval(s), and secondary confining layer(s) define the storage complex. The~~ confining system composed of a layered interval of low and moderate permeability rocks that will ~~purpose of the dissipation interval is to~~…provide ~~additional~~ opportunities…" (GCCC1_14-38)

Comment: "Risk assessment must be used to inform and design the monitoring." (GCCC1_14-39)

Comment: Best practice for storage requires application of a risk management approach to prevent loss from storage. Rajesh J.Pawar Grant S.Bromhal J. WilliamCarey WilliamFoxall AnnaKorre Philip S.Ringrose OwainTucker Mazwell N.Watson Joshua A.White[i], 2015, Recent advances in risk assessment and risk management of geologic CO_2 storage, Volume_40, September 2015, Pages 292-311

"…1) leakage risk or 2)…" (GCCC1_14-40)

Comment: The QM should be focused on assuring permanence and risk assessment is a key tool in this assurance. A call out of this best practice should be made.

"Risks of loss of CO_2 from storage must be evaluated based on the model of plume evolution and stabilization assessing permanence of storage. Uncertainties identified during characterization and well preparation must be inventoried and the impact on these uncertainties on storage permanence evaluated. Uncertainties that have a material impact on storage permanence must be managed via monitoring. Examples of possible material uncertainties include 1) high permeability zones that might lead to horizontal migration of the plume outside of the storage complex prior to stabilization, 2) natural or well-related flaws in the confining system that might allow vertical migration of CO2 out of the storage complex, 3) compartmentalization of the injection zone that might lead to elevated pressure; 4) geomechanically sensitive features that may be active by pressure change and increase risk of unacceptable seismicity. Risk assessment should inventory such material uncertainties and be used to design monitoring that will reduce leakage risk." (GCCC1_14-41)

Comment: Should be pragmatic

"…~~all~~ significant…" (GCCC1_14-42)

Comment: Spelling corrected

"…~~gauge~~ gouge…" (GCCC1_14-43)

Comment: These surface features are outside of storage complex, so AOR is correct. (GCCC1_14-44)

Comment: Should not require prospecting

"…~~any~~ known…" (GCCC1_14-45)

Comment: Presumable intentional venting will be done in an approved manner and not trigger emergency response

"…unintentional…" (GCCC1_14-46)

Comment: If rigor is required, a specification of quality of test results would be preferred to multiple tests.

"…~~the~~ at least one of the following transient analysis tests…" (GCCC1_14-47)

Comment: Is [confining system] this the "catch all" that is meant?

"…or calculate any additional physical and chemical characteristics…and confining ~~layer~~ system needed to augment…" (GCCC1_14-48)

Comment: Linking risk assessment to monitoring is critical to make sure that monitoring will catch (or prevent) any leakage

"…site characterization, risk assessment, modeling, and monitoring, risk management, quantification, and reporting activities…" (GCCC1_14-49)

Comment: This flow chart does not represent the process required in the QM. It should require risk management and accounting for CO_2 that has migrated out of storage complex. See suggested revision, attached in separate PPT file.

[Comment applies to Figure 5] (GCCC1_14-50)

Comment: Require even deviated wells that are spudded outside the AOR but enter the Storage complex

"…~~within the AOR~~…" (GCCC1_14-50a)

Comment: "…including the a detailed report on the model used…" (GCCC1_14-51)

Comment: To preserve integrity of the permanence documentation, if leakage outside the storage complex occurs, the QM SHOULD NOT let the operator just make a bigger AOR! In some cases, the loss is a real loss that will sooner or later reach the atmosphere. A reversal of credits has to be made. In other cases, the loss can be shown to not reach the atmosphere, but be effectively trapped in another rock volume. In this case, it would OK to justify an extension of the storage complex, after the justification is made and defended.

In many cases, good modeling and monitoring can be used to determine that the risk of out-of-complex migration is large before such loss occurs, and the injection operation adjusted. This outcome should be considered and favored.

"…~~AOR~~ plume location…" (GCCC1_14-52)

Comment: Specify that the model must be used to track the plume and support risk assessment

"…the Storage Complex and document via a risk assessment ~~over the life of the project~~ that it will contain the CO2 plume over the life to the project. The risk assessment must be ~~via a risk assessment~~ based on ~~on the model~~ ~~AOR using~~…" (GCCC1_14-53)

Comment: QM should require all these decisions to be documented in a report. As written, it looks like have an AOR outline on a map is the product, the required outcomes should be made more rigorous and clear.

"…and prepare a report of outcomes…" (GCCC1_14-54)

Comment: (2) is not strict enough. In a transmissive reservoir with good water drive (that is an ideal storage site from high injectivity/low seismic risk perspective), the

pressure will equilibrate much faster than the plume migration. Running the model to show the volume occupied at stabilization is essential to assuring permanence. Also not expensive, no penalty for running a calibrated model to stabilization.

"…~~or (2) until pressure differentials are no longer sufficient to lift either CO_2 or brine into the subsurface above the storage complex;~~" (GCCC1_14-55)

Comment: QM should require a detailed report on model design and sensitivity study. Otherwise model is not repeatable, has uncertain merit.

"…consider and report on the justification for the following…conduct and report on sensitivity ~~analysis~~ analyses and provide justification for ~~any~~ all simplifications…" (GCCC1_14-56)

Comment: Boundary conditions is a basic model element, not anon option. Because of significance of model boundary conditions to capacity and risk, (Ganjdanesh R., S.A. Hosseini, 2017, Geologic carbon storage capacity estimation using Enhanced Analytical Simulation Tool (EASiTool). *Energy Procedia*, 114, 4690-4696, https://doi.org/10.1016/j.egypro.2017.03.1601 and references therein) it is critical that the QM specify defining how they are selected

"…This data must be used to justify boundary conditions selected for the model relevant to pressure management during injection;" (GCCC1_14-57)

Comment: In some sites, previous injection may have occurred

"~~Pre-injection reservoir~~ Reservoir…" (GCCC1_14-57a)

Comment: must be "and.. The model must be set up to accept input from the monitoring program and repeat the assessment that the plume is contained and permanence criteria are met.

"Accept ~~E~~existing ~~or~~ and proposed operational and monitoring data, including the location of injection and/or extraction wells,…" (GCCC1_14-58)

Comment: The storage complex model will not include fresh water, is important here to include all fluids in injection zone which may change (e.g. during production)

"…~~groundwater~~ fluid…" (GCCC1_14-59)

Comment: Model design can have a profound impact on qualify of the model. Suggest that the QM not specify the model design, because advances are rapid in this technology, however the operator should be required to document and defend the selections made.

"~~Initial model~~ Model parameters such as: ~~(1)~~ initial conditions (e.g., fluid ~~pressures and flow rates~~ composition and distribution, etc.) … and (2) time steps and justification for

selection, (3) vertical and horizontal gridding design and justification that they are fit-to-purpose, and (4) and other model design parameters." (GCCC1_14-60)

Comment: Moved these criteria to more logical locations above to make clearer what is needed.

"…~~boundary conditions (i.e., the description of the conditions of the system) at the edges of the model domain and at the location of injection and/or extraction wells; and~~" (GCCC1_14-61)

Comment: CO_2 interactions with hydrocarbons are complex and require well-known computational assumptions. These should be specified and reported

"For injection into depleted reservoirs or CO_2 EOR operations, the measurements and computational assumptions (e.g. "black oil" or compositional model) made about the CO_2-fluid interactions must be specified, sensitivity analysis conducted, and the selected approaches justified;" (GCCC1_14-62)

Comment: Probabilistic and statistical methods of distributing attributes (e.g. facies model-based variograms) are available in most Earth model software and is a current best practice that should be encouraged.

"Probabilistic and statistical methods of distributing attributes should be documented and sensitivity analysis performed;" (GCCC1_14-63)

Comment: A good model will only include the data that are needed to create a valid model

"…must also be ~~included~~ considered in model development." (GCCC1_14-64)

Comment: Require use of all the pressure measurements. Document the quality of the match that it acceptable (it is never perfect)

"…assumptions used to ~~estimate the value of the~~ history match pressure ~~front~~ distribution;" (GCCC1_14-65)

Comment: Any uncertainties in model inputs that have a potential for major modeling prediction errors (leading to failure of storage) at the site must have follow-up assessment in risk assessment and then systematic testing by monitoring.

QM should not allow operators to provide only one simple "perfect" model. Modeling is the tool that is used in risk assessment and to design monitoring, such that permanence can be effectively demonstrated during operation.

"Modeling should ~~Consider~~ consider potential migration through faults, fractures, and artificial penetrations and determine the detectable response to such leakage, this outcome must be included in the risk assessment and monitoring plans and operations; and

… Any material uncertainties (those that could result in loss of storage permanence) must be considered in the modeling. Models showing the impact of uncertainties must be considered in the risk analysis to determine how the material uncertainties can be detected by monitoring." (GCCC1_14-66)

Comment: Requiring open source code creates major flaws in advanced problems such as 1) hydrocarbons in the reservoir and 2) geomechanics solutions, where commercial codes advance more quickly. If CARB itself want to repeat the modeling a better method is to require 1) the gridded and parameters in common XYZ format, and 2) the input files.

"…delineation ~~model~~ and plume tracking must be validated for the uses in peer-reviewed literature. ~~open~~ Open source code and publically available to CARB and CCS Project Operators ~~and,~~is ~~preferably~~ preferred~~,~~. ~~be reported in peer reviewed CCS literature~~:" (GCCC1_14-67)

Comment: It is likely that more than one code will be needed

"The code(s) used…" (GCCC1_14-68)

Comment: Substitute a performance-based requirement. For perspective. The best code is one that requires the minimum data and the fastest run-time to get a reasonable approximation of the reservoir response.

"…must be demonstrated to be capable of 1) predicting the evolution of 3-D geometry of the CO_2 plume under reservoir conditions at the site during injection and after injection during stabilization; 2) support risk assessment by allowing evaluation of the response of key intervals to leakage response; 3) support assessment of geomechanical response to pressure and fluid change during injection, especially with regard to risk of induced seismicity; 4) provide a reliable timeline showing plume and pressure stabilization, and 5) support comparison of the modeled response to the reservoir response during monitoring~~,~~ Techniques to demonstrate that the code is appropriate include 1) successful application in a similar setting leading to successful history matching; 2) comparison of a new code against a proven code to show reasonable match, or 3) sensitivity studies showing that the code reproduces the relevant physics properly." (GCCC1_14-69)

Comment: This list is not at this time practical, no single existent code can do all this. Most of these functions are not relevant to real storage problems. Typically non-isothermal problems involving phase changes are solved in one code set, gravity-dominated dissolution in another core set, and problems involving miscibility in a different code (usually commercial)

"~~at a minimum, consider multiphase flow of CO_2 in supercritical, liquid, and gaseous phases, including miscible and immiscible displacement, CO_2 dissolution in groundwater, density driven flow, and the impact of injection on groundwater flow patterns;~~" (GCCC1_14-70)

Comment: These are basics of CO2-brine porous media systems.

"…Codes ~~may also be further modified to allow for complex~~ must properly manage key properties of the reservoir fluid system including three-dimensionally heterogeneous formations; and ~~residual phase trapping;~~ characteristic-curve hysteresis and residual phase trapping~~;~~…" (GCCC1_14-71)

Comment: Any leaking wells are of concern.

"…The system response to leakage through faults, fractures, and ~~abandoned~~ wellbore…" (GCCC1_14-72)

Comment: Make sure model is fit-to-purpose

"…the developer must ~~verify~~ validate the model's ~~accuracy~~ appropriateness by modeling validated test cases of problems with similar physics…" (GCCC1_14-73)

Comment: CARB should expect multiple updates will be run.

"The ~~modeled~~ model must be updated with all additional ~~site~~ characterization and pre-injection testing and ~~AOR~~ will be finalized after ~~all site data are collected and pre-injection testing is~~ this update is complete. Versions of the model must be given unique identifiers." (GCCC1_14-74)

Comment: include any post closure CO2 migration in the storage complex definition

"…pressure until it stabilizes after the end of injection…" (GCCC1_14-75)

Comment: All the wells must be included; they will interfere and change the plume shape and pressure evolution. Idealized one-well cases are easier to build and run but must be avoided if the project has multiple wells

"…modeling exercise ~~may~~ must be conducted…" (GCCC1_14-76)

Comment: "Aerial photography and…" (GCCC1_14-77)

Comment: Normally, corrective action is staged, such that wells near the injection will be worked over first. Far away wells can be re-entered at later stages of the project.

"…must ~~perform~~ plan corrective action…" (GCCC1_14-79)

Comment: Include deviated wells that are not in AoR that come into storage complex. (GCCC1_14-79a)

Comment: This must be a full 3-D evaluation, not a map view. Many known leakages are vertical, e.g. subsurface blowouts.

Much of this seems redundant to above.

"~~AOR~~ Plume Reevaluation" (GCCC1_14-80)

Comment: The first key question is if the model calibrated with observations is still within the Storage complex

"…and determine if it is within the storage complex;" (GCCC1_14-81)

Comment: The second key question is if the model calibrated with observations is still predicted to stay within the Storage Complex after closure

"…and rerun the model to predict if the model calibrated with updated observations is predicted to stay within the Storage Complex until plume stabilization;" (GCCC1_14-82)

Comment: Loss of CO_2 from the storage complex is a serious problem for permanence and generally should trigger reversals.

"(3) If the plume has already left the storage two options can be considered:" (GCCC1_14-83)

Comment: In some cases, CO_2 that has migrated in an unplanned way will eventually escape to atmosphere, or there is uncertainty that it will be permanently stored. E.g. CO_2 that migrated above upper-most confining layer.

"(1) Quantify a reversal of credits for the mass of CO_2 that migrated out of the Storage Complex" (GCCC1_14-84)

Comment: In other cases, CO_2 that has migrated in an unplanned way is *unlikely* to escape to the atmosphere, and the operator can make a demonstration that this is true by expanding the storage complex delineation to include the extension (lateral or vertical) areas.

"(2) Qualify additional rock volumes to be added to the Storage Complex for permanent storage by modifying the definition of the storage complex and repeat the activities:" (GCCC1_14-85)

Comment: "A) Identify all wells in the ~~reevaluated AOR~~ Modified storage complex that require corrective action…" (GCCC1_14-86)

Comment: Pragmatically this is a very important option used in commercial injection projects. Operators may change the injection amount, injection rate, modify well completions, or drill additional well(s).

"(4) If the updated model of the plume predicts that CO2 will leave the storage complex before stabilization but no leakage has occurred:

(5) Same option (1) and (2) above

(6) or (3) modify the injection plan so that the modeled plume remains inside the Storage Complex until stabilization" (GCCC1_14-87)

Comment: It is unacceptable to update the model without doing a re-evaluation of permanence, and if needed a modification of the Operation

"(7) Submit either,(1) an updated model output showing that CO2 will be retained inside the Storage Complex until stabilization. (2) a quantification of CO2 that was lost from the Storage Complex, or (3) an amended ~~AOR~~ Storage Complex delineation or operational plan showing that changes made will result in CO2 being retained inside the Storage complex until stabilization ~~and Corrective Action Plan including a description of the changes made to the model and a justification of those changes, or demonstrate to the Executive Officer through monitoring data and modeling results that no amendments to the AOR and Corrective Action Plan are needed. Any amendments to the AOR and Corrective Action Plan, or demonstrations of no changes to the AOR and Corrective Action Plan, must be approved by the Executive Officer, and must be incorporated into the Permanence Certification.~~" (GCCC1_14-88)

Comment: If the injection operation or Storage complex is redefined, the monitoring plan must be updated.

"The Emergency and Remedial Response Plan, Monitoring plan Post-Injection Site Care and Closure Plan, and…" (GCCC1_14-89)

Comment: "…monitoring data…" (GCCC1_14-90)

Comment: "…reevaluate the size and shape of the CO_2 plume through the project life until plume stabilization ~~AOR~~ as specified…"

"…the actual CO_2 free-phase plume ~~or pressure front~~ or predicted plume at stabilization may extend beyond ~~the area originally modeled, the~~ the Storage Complex ~~CCS Project Operator must reevaluate the AOR, and the~~ following steps…" (GCCC1_14-91)

Comment: If a material error is found, such a plume that has or will extent out of the storage complex, corrective actions must be taken

"…reevaluate the injection plan, the project accounting, or the Storage complex delineation, risk assessment and monitoring plan AOR…" (GCCC1_14-92)

Comment: "…no ~~reevaluation of the~~ corrective action ~~AOR~~ is needed." (GCCC1_14-93)

Comment: Loss of CO_2 from the storage complex is a serious problem for permanence and generally should trigger reversals.

"(4) If the plume has already left the storage two options can be considered:" (GCCC1_14-94)

Comment: In some cases, CO_2 that has migrated in an unplanned way will eventually escape to atmosphere, or there is uncertainty that it will be permanently stored. E.g. CO_2 that migrated above upper-most confining layer in system

"(1) Quantify a reversal of credits for the amount of CO_2 that migrated out of the Storage Complex" (GCCC1_14-95)

Comment: In other cases, CO_2 that has migrated in an unplanned way is *unlikely* to escape to the atmosphere, and the operator can make a demonstration that this is true by expanding the storage complex delineation to include the extension (lateral or vertical) areas.

"(2) Qualify additional rock volumes for permanent storage by modifying the definition of the storage complex and repeat the activities:

A) Identify all wells in the Modified storage complex that require corrective action in the same manner specified in subsections C.2.4.2 and C.2.4.3;

B) Perform corrective action on wells requiring corrective action in the reevaluated AOR in the same manner specified in subsections C.2.4.3 and C.2.4.3(d); and" (GCCC1_14-96)

Comment: Pragmatically this is a very important option used in commercial injection projects. Operators may change the injection amount, injection rate, modify well completions, or drill additional well(s).

"(5) If the updated model of the plume predicts that CO2 leave the storage complex before stabilization but no leakage has occurred:

(6) Same option (1) and (2) above

(7) or (3) modify the injection plan so that the modeled plume remains inside the Storage Complex until stabilization" (GCCC1_14-97)

Comment: It is unacceptable to update the model without doing a re-evaluation of permanence, and if needed a modification of the Operation

"~~(1)~~ Submit either,(1) an updated model output showing that CO2 will be retained inside the Storage Complex until stabilization. (2) a quantification of CO2 that was lost from the Storage Complex, or (3) an amended Storage Complex delineation or operational plan showing that changes made will result in CO2 being retained inside the Storage complex until stabilization ~~Revision of the site conceptual model based on new site characterization, operational, or monitoring data;~~

~~(2) Recalibration of the model to minimize the differences between monitoring data and model simulations; and~~

~~(3) Re-delineate the AOR as described in subsections C.2.4.2 and C.2.4.4.~~" (GCCC1_14-98, GCCC1_14-88)

Comment: "…~~AOR~~ observations and model,…" (GCCC1_14-99)

Comment: "…~~AOR~~ Plume evolution…" (GCCC1_14-100)

Comment: The QM must not automatically allow the storage complex to be made larger. Some rock volumes are not suitable for permanent storage. If CO2 migrates into these volumes credits must be reversed. Note that such migration may not present HS&E risk.

"…~~AOR~~ plume extent…" (GCCC1_14-101)

Comment: The focus needs to be on the storage permanence performance. Changing the AOR should only be allowed if permanence in the new volumes can be demonstrated.

"…~~AOR~~ plume extent…" (GCCC1_14-102)

Comment: CARB QM should keep a strong focus on goal B. Goal A should be primarily covered by other injection permitting authorities, e.g. UIC program

"…that (1) may endanger public health or the environment or (2) require reversals of the storage credits because of failure to attain permanence." (GCCC1_14-103)

Comment: Key performance indicators

"…subsurface monitoring must be designed to detect leakage from the storage complex and to the atmosphere using site-specific criteria…" (GCCC1_14-104)

Comment: Pressure and geophysical tools should be considered also; they have often been shown to detect smaller leakage at earlier times.

"…variability in physical and ~~geo~~chemical parameters…" (GCCC1_14-105)

Comment: The key role of preinjection data is to model effective detection. If there is too much noise and variability, an alternate method must be required.

"(d) Baseline data on ~~CO_2 concentrations and fluxes~~ physical and chemical conditions collected prior to operation must be used to design a monitoring program that is capable of detecting leakages. ~~for~~ Baseline data may be used for history matching… Variability at daily, seasonal or created by long duration trends (e.g. climate change, sea level rise, urbanization or other landscape evolution) must be considered and may require advanced approaches to separate leakage signal from other changes.

(e) Any properties of the storage complex, groundwater, overburden, or AOR that is shown by Risk Assessment to potentially be impacted by injection ~~may affect baseline data~~ must be evaluated, including but not limited to: downhole pressure, sequestration zone fluid chemistry, ~~surface~~ soil gas composition ~~type~~, ~~soil organic carbon content,~~ vegetation type and density, ~~topography,~~ and ~~surface~~ fresh and overburden water ~~hydrology~~ chemistry and pressure." (GCCC1_14-106)

Comment: "The ~~determination of the~~ baseline monitoring strategy must be ~~determined~~ sufficient to detect, verify, quantify, mitigate, and validate mitigation of CO_2 leakage out of the storage complex on a site-specific basis…" (GCCC1_14-107)

Comment: For correct accounting, as much or more care should be put into baseline environmental monitoring.

"Baseline data collection in the injection zone and confining system may be needed to track the evolution of the CO2 plume. Geophysical tools such as seismic, electrical, gravity, pulsed neutron and other tools in particular are much more quantitative used in time-lapse mode (surveys collected prior to injection compared to those collected during and after injection). Pressure and chemical tools also may benefit from baseline data." (GCCC1_14-108)

Comment: The concept of baseline only works if the survey can be repeated without error. Serious limitations should be considered.

"in all cases attention (subsurface and surface), the process by which the survey can be accurately repeated in terms of location and instrumentation must be provided" (GCCC1_14-110)

Comment: "For soil gas and air sampling, the baseline monitoring must be shown to allow CO_2 leakage to be detected, verified, and quantified. ~~spatial~~ Spatial distribution of, ~~of soil CO_2 fluxes and concentrations must be determined on a site-specific basis, but requires, at a minimum,~~ repeat measurements at ~~several~~ fixed sites~~, and~~ over a period of one year or more~~,~~ are required to capture any seasonal or diurnal variations. CCS Project Operators must plan the location and frequency of soil gas and surface air sampling ~~points~~ based on the following considerations:" (GCCC1_14-111)

Comment: Known leakage from subsurface blowouts escapes to the surface at discharge points, these may be boggy and highly variable.

"~~(A) Avoid areas with highly fluctuating background concentrations, based on previously recorded data;~~" (GCCC1_14-112)

Comment: Techniques such as process-based (Romanak, K. D., Bennett, P. C., Yang, C., and Hovorka, S. D., 2012, Process-based approach to CO_2 leakage detection by vadose zone gas monitoring at geologic CO_2 storage sites: Geophysical Research Letters, v. 39, L15405, doi:10.1029/2012GL052426.) or natural tracer methods should be used to manage noise.

"(A) Soil gas and air monitoring locations should be selected at the points at which should leakage occur, detection would be likely, based on risk assessment. A strategy to separate leakage signal from noise must be provided. A method for separating leakage signal from long-term trend (e.g climate change) must be provided. Features that may lead to anomalies in gas composition should be assessed (for example past land use, shallow methane accumulations, increased wetlands resulting from sea level rise)" (GCCC1_14-112a)

Comment: "Target potential point sources of leakage, including…" (GCCC1_14-113)

Comment: New technologies such as buried fiber or laser detection in air have been tested and will likely provide better and lower cost options than LICOR stations.

"~~A grid methodology, must be used when~~ Sufficient coverage must be obtained for monitoring soil gas and atmosphere for non-point source leakage throughout the AOR. ~~Grid cell spacing may range over several orders of magnitude, depending on site-specific factors~~." (GCCC1_14-114)

Comment: "…must include geophysical, pressure and chemical data from the subsurface…" (GCCC1_14-115)

Comment: CARB should require the operator to do this otherwise it is a large burden on the agency to do the whole analysis of significance of findings in-house

"…assess of the impact of baseline site characteristics on operational and long term monitoring and…" (GCCC1_14-116)

Comment: It is likely that the locations will not serve as a simple "baseline" as landscape evolution e.g. driven by climate changes, land use changes, sea level change will occur over 100 years. If CARB requires ecosystem monitoring, methods to deal with these changes should be proposed.

"…and ~~that~~ determine if potential point sources are represented and if locations will serve…" (GCCC1_14-117)

Comment: Note that in a proper storage project, information on the ecosystem characteristics continue during the operation (any leakage would be localized). (GCCC1_14-118)

Comment: Static fluid level is a not very useful in deep wells, because the density of the fluid column is poorly constrained.

"The CCS Project Operator must record the fluid temperature, pH, conductivity, reservoir pressure~~, and static fluid level~~ of the sequestration zone." (GCCC1_14-119)

Comment: "…, or unacceptably increase risk of significant induced seismicity." (GCCC1_14-120a)

Comment: Not all wells in the project may be affected. If possible the project should keep receiving CO2 to prevent release by the source.

"…cease injection into the affected well(s),…" (GCCC1_14-121)

Comment: The monitoring plan needs to be designed to provide input data needed to validate the model and assure that the plume will remain inside the storage complex at stabilization.

"(11) Monitoring will provide data to assess the horizontal and vertical location of the plume in 2.4.2 and determine if it is within the storage complex. In addition, monitoring data will be used to test if the modeled migration of the plume prior to stabilization remains within the storage complex.

(12) Monitoring will be used to detect and quantify leakage. The process and detection threshold at which leakage from any possible pathway from reservoir to surface will be detected and quantified should be specified. Maps and modeling should be used to show how measurement and modeling will be used to trigger a finding of leakage. Monitoring will be used to verify and quantify the loss. Monitoring will be used to show that any mitigation is effective." (GCCC1_14-122)

Comment: A practical plan is needed, especially in more complex multi-well systems. EOR in particular requires a more sophisticated site specific measurement system. CO_2 injected in EOR requires accurate accounting at the facility gate (custody meter) prior to comingling with recycled and impure CO_2, then accurate allocation to injectors.

"…The method that assures as accurate as feasible quantification must be shown. Issues such as variable pressure and temperature and the impact of impurities on volume to mass conversion must be considered. In cases such as CO2 EOR where CO2 handling is complex, an inventory of the flows must be provided that avoids any error such as double counting recycled CO2. ~~, metered at the wellhead.~~" (GCCC1_14-123)

Comment:

"(14) The CCS project operator must inventory and show the suitability using site-specific and risk assessment based data of the methods that will be used to provide data required in in 2.4 for updating the plume location, predicting the location at stabilization, updating the computer modeling, and assessing the permanence of storage within the Storage Complex

(15) Quantify and provide estimation methods, precision and accuracy of measurement of any CO_2 that migrates outside the storage complex and cannot be qualified as permanently stored as required in section 2.2 (e) equation 6. See section 2.4 for corrective actions that can be used to avoid reversals.

(16) Quantify and provide estimation methods, precision and accuracy of measurement of atmospheric CO_2 leakage from the storage complex (MT CO_2/year) as required by 2.2.(e) eq 6." (GCCC1_14-124)

Comment: Downhole gauges are left installed (to meet other requirements) and cannot be calibrated a surface. (GCCC1_14-125)

Comment: "Continuous recording devices to monitor: the injection pressure…and annulus fluid volume, including calibration and accuracy data;…" (GCCC1_14-126)

Comment: Normally should not be fluids in gas phase in the system.

"CCS project monitoring techniques must use calibrated metering equipment such as ~~gas~~ fluid flow meters, utility meters (gas and electricity) and ~~gas~~ fluid chemistry analyzers." (GCCC1_14-127)

Comment: It is not acceptable to mix in a minor hazardous fluid

"…include a determination that ~~the~~ no component of the injectate does not meet the qualifications of hazardous waste…" (GCCC1_14-128)

Comment: For complex mixed streams from more than on source or EOR the burden should be on the operator to show composition is representative.

"…collected from a point ~~immediately upstream or downstream of the flow meter~~ that must be shown to be representative of the composition of the injectate. In complex systems this may require showing calculations." (GCCC1_14-129)

Comment: Most CO_2 will be dense phase

"Continuous measurement of the gas flow rate, ~~gas~~ fluid composition, and ~~gas~~ density,…" (GCCC1_14-130)

Comment: In complex systems such as EOR or mixed capture steams, the QM should place the burden of justifying that the measurement at a location is representative and supports the accounting on the operator.

"Flow meters must be located where the can make an accurate measurement for accounting purposes and the meter placement must be justified. ~~immediately upstream the gas injection process, such that they are downstream of all capture, compression, and transport to account for any fugitive losses or venting.~~" (GCCC1_14-131)

Comment: The location should be justified for complex streams and EOR. In EOR just upstream of the injection well the injected is contaminated by recycled CO2. Metering at EOR must take place prior to mixing new and recycled CO_2, and accounting must deal with commingled and separate flows correctly.

"…volume is measured ~~immediately~~ upstream…" (GCCC1_14-132)

Comment: See CCS monitoring goals Jenkins, C., Chadwick, A. and Hovorka, S.D. 2015. The state of the art in monitoring and verification--ten years on. International Journal of Greenhouse Gas Control, Vol. 40. Pp. 312-349. doi:10.1016/j.ijggc.2015.05.009

"…CO_2 is being injected into, including a demonstration that the methods selected are sensitive to the CO_2 plume in the geologic environment of the storage reservoir, to 1) validate the fluid flow model that shows that the plume will remain within the storage complex until stabilization and 2) ensure ~~measurements of emissions~~ that if migration out of the storage complex or to the surface occur, that they are detected ~~and~~ with a detection threshold ~~is~~of 5% of the CO_2 injected over the project lifetime. ~~from the sequestration zone are within five percent of measurement accuracy and precision.~~" (GCCC1_14-133)

Comment: To make the intent clear

"…CO_2 plume and elevated pressure ~~front~~, any emissions of injected CO_2 that migrate to the surface, and natural and induced seismic activity." (GCCC1_14-134)

Comment: "…must include methods and plans for the quantification of CO_2 leakage or losses from the storage complex if it occurs,…" (GCCC1_14-135)

Comment: "…including an estimate of the accuracy and precision of those methods,…" (GCCC1_14-136)

Comment: A "front" is insufficient. Pressure must be measured and modeled to determine if pressure increases within acceptable ranges over the whole storage complex. Sensitive points such as faults may be of special interest.

"…the pressure development within the storage complex ~~(e.g., the pressure front)~~ by using:" (GCCC1_14-137)

Comment: Should include the confining systems, especially the dissipation zone if present

"~~Direct~~ Well-based methods in the ~~sequestration zone~~ storage complex; and…" (GCCC1_14-138)

Comment: Electrical included in electromagnetic

"Indirect methods such as seismic, ~~electrical,~~ gravity, or electromagnetic…" (GCCC1_14-139)

Comment: Downhole methods are same as direct methods.

"…surveys ~~and downhole~~ CO_2 detection tools." (GCCC1_14-140)

Comment: "(b) …confirm that monitoring observations of plume location, thickness, and saturation ~~agree with~~ validate the ~~AOR~~ model results, ~~and~~ to confirm that the plume and pressure development within the ~~sequestration zone~~ storage complex, update the model to determine if the plume will remain in the storage complex until stabilization, and that operations are not leading to elevated leakage or seismic risks. The monitoring plan should be linked to the risk assessment and an effective part of the risk management for the project. Prior to project approval and during operations, the operator must demonstrate that the monitoring methods will be, and are sensitive at the site to detect the change that they are intended to measure." (GCCC1_14-141)

Comment: "Site-specific modeling and field testing must demonstrate that the monitoring approach will be effective in detecting the monitored parameter and will be effective in detecting leaked CO_2 or confirming no loss of CO_2 to the atmosphere." (GCCC1_14-142)

Comment: "…any deviations from the modeled ~~AOR~~ plume geometry,…" (GCCC1_14-145)

Comment: "…results trigger ~~an~~ a reversal of credits or…" (GCCC1_14-146)

Comment: "(4) The monitoring approach and equipment should periodically be reevaluated to determine if: 1) useful and accurate data are collected by the methods and, 2) if improved methods are available." (GCCC1_14-147)

Comment: Baseline data itself is unlikely to provide much guidance. Analysis will be required. S ee example in Etheridge, D., Luhar, A., Loh, Z., Leuning, R., Spencer, D., Steele, P., Zegelin, S.,Allison, C., Krummel, P., Leist, M., van der Schoot, M., 2011. Atmosphericmonitoring of the CO2CRC Otway Project and lessons for large scale CO2storage projects. 10th Int. Conf. Greenh. Gas Control Technol. 4,3666–3675.

"…monitoring must be decided ~~using~~ by analysis of baseline data…" (GCCC1_14-148)

Comment: If leakage is occurring, the AOR should not be changed, a reversal should be made instead. Leakage to surface is an unexpected and potential consequential error, and preparation for this low likelihood high consequence event should be serious.

"…~~and the monitoring plan must describe how the proposed monitoring will yield useful information on the AOR delineation or reevaluation.~~ Methods must be able to distinguish leakage signals from other changes, such as land use, climate, and ecosystems. Methods must be able attribute the source of leakage, potentially manage or reduce future leakage, and quantify the losses, including any CO_2 which has escaped from the storage complex and is migrating toward the surface." (GCCC1_14-149)

Comment: Not realistic because of high CO2 concentrations in the atmosphere.

"Operators must use both intermittent and continuous monitoring methods~~, must consider the following tools to track CO2 in the atmosphere~~:" (GCCC1_14-150)

Comment: See Etheridge, D., Luhar, A., Loh, Z., Leuning, R., Spencer, D., Steele, P., Zegelin, S.,Allison, C., Krummel, P., Leist, M., van der Schoot, M., 2011. Atmosphericmonitoring of the CO2CRC Otway Project and lessons for large scale CO2storage projects. 10th Int. Conf. Greenh. Gas Control Technol. 4,3666–3675.

"Soil gas monitoring of point sources: The CCS Project Operator must perform continuous and intermittent geochemical monitoring of the soil and vadose zone, including sampling of CO_2, ratios of CO2 to other gases (the process-based method), natural chemical tracers, and introduced tracers, …" (GCCC1_14-151)

Comment: This is critical, see example from problem at Weyburn, see Romanak, K. D., Wolaver, B. D., Yang, C., Sherk, G. W., Dale, J., Dobeck, L. M., and Spangler, L. H., 2014, Process-based soil gas leakage assessment at the Kerr Farm: comparison of results to leakage proxies at ZERT and Mt. Etna: International Journal of Greenhouse Gas Control, v. 30, p. 42-57, http://doi.org/doi:10.1016/j.ijggc.2014.08.008.

"…natural chemical tracers, and introduced tracers, in order to detect potential releases from wellbores, faults, and other migration pathways, and separate ecosystem variability from leakage signal and must consider the following methods:" (GCCC1_14-152)

Comment: Wells are preferred because of the need reproducibly repeat monitoring over time.

"Active sample collection methods including shallow monitoring wells, ground probes and permanent soil gas probes;" (GCCC1_14-153)

Comment: Sorbants are only valuable if PFT's have been introduced, a high GHG impact that should be avoided except for R&D. (GCCC1_14-154)

Comment: All wells should be surveilled. Note that the known leakage has been from wells in operation, e.g. Aliso Canyon well in gas storage, See also http://www.rrc.state.tx.us/oil-gas/complianceenforcement/blowouts-and-well-control-problems/

"Monitoring of ~~legacy wells and~~ all wellbores: The CCS Operator must monitor all ~~temporarily abandoned and plugged and abandoned~~ wells that intersect the storage complex at depth." (GCCC1_14-155)

Comment: "Monitoring should include direct observation of the wells if possible, soil gas and surface air monitoring around the wellbore, and should focus on identifying CO_2 flux ~~around~~ in the vicinity of the wellbore that may indicate a catastrophic leak." (GCCC1_14-156)

Comment: Dilution is fast, no ecosystem stress results from release to air.

"Ecosystem stress monitoring: CCS Project Operators must conduct annual vegetation surveys to measure potential vegetative stress resulting from elevated CO2 in soil ~~or air~~." (GCCC1_14-157)

Comment: Process-based method should be next required step to determine if CO2 has displaced other soil gases. See Romanak papers cited above.

"…must be analyzed to determine the presence or absence of sequestration zone brine or characteristics of ~~artificial tracers introduction of~~ injected ~~with the~~ CO_2, including introduced tracers." (GCCC1_14-158)

Comment: In almost all cases the quarterly analysis will need significant interpretation; reports are not likely to be high quality on a quarterly basis.

"Surface and near-surface monitoring data must be reported and interpreted ~~quarterly for methods in which data are collected continuously, and~~ annually ~~for methods in which data are collected less frequently, based on the monitoring timeline pursuant to subsection~~ C.4.3.2.2(c)." (GCCC1_14-159)

Comment: Soil gas and atmospheric methods will not be useful in modifying the storage complex and AOR, which are based on plume tracking in the subsurface. If leakage is detected, it should be attributed, quantified and an assessment of credit reversal, as well as consideration if leakage can be stopped or mitigated

"~~(3) An assessment of any deviations from the modeled AOR, if observed, and the determination of whether or not the results trigger an AOR reevaluation;~~ If leakage is detected, it should be attributed, quantified and an assessment of credit reversal, as well as consideration given if leakage can be stopped or mitigated;" (GCCC1_14-160)

Comment: Microseismicity will be focused at geologic features. See Surface Monitoring of *Microseismicity* at the *Decatur, Illinois*, CO2. Sequestration. Demonstration Site by J. O. Kaven, S.H. Hickman, A. F. McGarr, and W. L. Ellsworth**.**

"The CCS Project Operator must deploy and maintain a permanent, downhole seismic monitoring system in order to verify the presence or absence of any induced micro-seismic activity within the vicinity of each injection well or near any discontinuities, faults, or fractures in the subsurface." (GCCC1_14-161)

Comment: Downhole observation of microseismicity is a currently increasing best practice for injection projects. However, it is not valuable unless significant analysis is conducted and reported, and unless a response to increased risk is required.

"The design of the array should consider the seismic risk. Location of small events can be helpful in risk reduction, but sufficient planning is needed to collected and analyze the data. Analysis of the microseismicity must consider if the risk of triggering an earthquake of Richter magnitude 2.7, or greater, is significantly increased by injection. If an increase is risk is detected and determined, mitigation of risk should be required.

The array should be calibrated with check-shots, preferably at depth." (GCCC1_14-162)

Comment: Time needed to complete analysis.

"The preliminary results of the seismic evaluation must be reported to the Executive Officer within 30 days following the earthquake with final report within 120 days. The report must include, at a minimum:" (GCCC1_14-163)

Comment: Some excellent sites without water drive (e.g depleted gas fields) may stabilize at elevated pressure.

"The pressure differential between pre-injection and predicted post-injection pressures in the sequestration zone, and the predicted timeframe in which pressure is expected to ~~decrease to pre- or close to pre-injection levels;~~stabilize" (GCCC1_14-164)

Comment: "…at site closure as demonstrated in the ~~AOR~~ final validated ~~evaluation and~~ computational modeling required at subsections C.2.4 and C.2.4.1;" (GCCC1_14-165)

Comment: Pressure in all settings will begin to decrease as soon as injection stops (see Freeze and Cherry, Groundwater, SBN-13: 978-0133653120, on hydrologic testing) .CO_2 plume movement will also begin to abruptly decrease. These results can be matched to the model predictions and established a reliable trend toward stabilization (which is much simpler than during the expansion phase). CARB should balance the relatively high leakage risk of open wells against the rapidly decreasing risk of plume migration. If possible, monitoring methods that close wells that penetrate the injection zone should be favored over open wells.

"Monitoring and observation wells must remain open, and in active monitoring mode, until the CO_2 plume can be seen to be ~~reaches a stable state in which the pressure front is no longer increasing in radius (or is decreasing) and conforms~~ conforming to model predictions pursuant to subsection C.2.4.1,…" (GCCC1_14-167)

Comment: "…and until CARB agrees plume stability ~~has occurred~~ trend has been established and leakage risk decreased. Risk reduction including sequentially plugging wells that penetrate the CO_2 plume in favor of remote methods and surveillance outside and above the plume should be adopted." (GCCC1_14-168)

Comment: If wells are essential enough to keep open and accruing that small but known risk, then they must be replaced if damaged.

"If the leak cannot be remediated, the well must immediately be plugged and abandoned pursuant to subsection C.5.1(d) a new well must be drilled to fill the plugged well's role." (GCCC1_14-169)

Comment: Quarterly is very high frequency and if conducted in areas of CO_2 charge introduces significant and unneeded risk. Note frequency of blowout during well work

overs, http://www.rrc.state.tx.us/oil-gas/complianceenforcement/ blowouts-and-well-control-problems/

"Conduct ~~quarterly~~ bottom-hole pressure ~~tests~~ measurmentss in the monitoring wells in order to track the ~~position of the~~ pressure changes. Frequency of measurement can be based on the previously measured rate of change~~front~~;" (GCCC1_14-170)

Comment: "Periodically update the ~~AOR delineation~~plume mapping pursuant to subsection C.2.4 to determine if any corrective action is necessary and to establish if the CO2 plume has stabilized." (GCCC1_14-171)

Comment: To reduce HS&E risk, CARB should accelerate P&A of wells as soon as confidence that risk is well managed.

"Once ~~the~~ a trend toward CO2 plume stability has been demonstrated, all CCS project wells may be abandoned following subsection C.5.1(d)." (GCCC1_14-172)

Comment: During P&A the wellhead should be removed and casing cut off.and welded shut below grade.

"Soil-gas and surface-air monitoring at, and within 10 ft of, the former wellhead or well pad; and" (GCCC1_14-173)

Comment: At P&A wellhead will be removed and casing cut off below ground surface.

"Visual inspection of the ~~wellhead and~~ the land surface within a 100 ft radius of the cut off wellhead or well pad." (GCCC1_14-174)

Comment: Note that leakage is rare but in known cases, fluid migration is not usually vertical but has lateral components, moving to land surface at discharge points.

"Areas that risk assessment shows should any leakage occur, would be preferential pathways for CO2 or brine migration should be inspected and if needed tested." (GCCC1_14-175)

Comment: A lot of changes that will happen to the site are outside of the operators control.

"At the direction of the Executive Officer, the CCS Project Operator must also restore the site to a condition agreed with Executive Officer. ~~its pre-injection condition."~~ (GCCC1_14-176)

Comment: Depending on nature of risk, other wells in a multi-well project may be able to safely continue to accept CO2.

"Immediately cease injection in affected well(s);" (GCCC1_14-177)

Comment: This ["A dissipation interval directly above the storage complex with at least one secondary confining layer between the surface and the dissipation interval."] should be part of a confining system. Specifying three layers is a poor description, see actual geologic settings, which should be multilayered. (GCCC1_14-179)

Comment: Definitions (80): "Net working capitol" should be "Net working capital". (CCSPD1_106-39a)

Comment: *"The pressure differential between pre-injection and predicted post-injection pressures in the sequestration zone, and the predicted timeframe in which pressure is expected to ~~decrease to pre- or close to pre-injection levels~~ stabilize;"* (CCSPD1_106-44)

Comment: *"Monitoring and observation wells must remain open, and in active monitoring mode, until the CO_2 plume reaches a stable state in which the pressure ~~front~~ is no longer increasing ~~in radius~~ (or is decreasing) and conforms to model predictions pursuant to subsection C.2.4.1, and until CARB agrees a substantial trend in plume stabilization~~ty~~ has been demonstrated to the satisfaction of the Executive Officer. ~~occurred.~~"* (CCSPD1_106-46)

Comment: *"Periodically update the ~~AOR~~Storage Complex delineation pursuant to subsection C.2.4 to determine if any corrective action is necessary ~~and to establish if~~ until a trend in CO_2 plume stability has been demonstrated ~~has stabilized~~."* (CCSPD1_106-49)

Comment: *"Conduct leak detection checks at each well that is part of the CCS project, and in the near surface close to each plugged and abandoned well until the CO_2 plume ~~has~~ stabilize~~d~~ation trend is demonstrated to the satisfaction of the Executive Officer."* (CCSPD1_106-50)

Comment: *"Once the trend in CO_2 plume stability has been demonstrated, all CCS project wells may be plugged and abandoned following subsection C.5.1(d)."* (CCSPD1_106-51)

Comment:

"~~1. Soil-gas and surface-air monitoring at, and within 10 ft of, the wellhead or well pad; and~~

~~2. Visual inspection of the wellhead and the land surface within a 100 ft radius of the wellhead or well pad.~~" (CCSPD1_106-52)

Comment: Make correction to change the Table reference from Table 1 to Table 2.

"Risk scenarios identified as part of this assessment must be classified according to probability of occurrence during a 100-year period (see Table 2~~1~~,below)." (RFVV1_126-7)

Comment: Delete “that” as shown to correct a typo. As currently written, the sentence is ungrammatical and does not make sense.

“Model results must be presented in contour maps, cross sections, and/or graphs showing plume and pressure front migration as a function of time, and ~~that~~ the application for Sequestration Site Certification submittal must include the outcome of parameter sensitivity analysis and model calibration.” (RFVV1_126-8)

Comment: The provision in C.2.5(f)(1) is sufficient as a requirement because it dictates reliance on the site-specific risk assessment and the use of a site-specific approach. The specific approach of examining potentially irrelevant CO_2 fluxes should not be dictated. Nevertheless, directing careful location of any monitoring arrays and sampling points used is sensible.

“For any soil and air sampling, the ~~spatial distribution of soil CO_2 fluxes and concentrations must be determined on a site-specific basis, but requires, at a minimum, repeat measurements at several fixed sites, and over a period of one year, to capture any seasonal or diurnal variations.~~ CCS Project Operators must plan the location of soil gas and surface air sampling points based on the following considerations:” (RFVV1_126-12)

Comment: There is an error in the current language. The suggested revision would cure the error, as would a change to say “ensure **against** the likelihood” while deleting “is not likely” at the end of the sentence.

“The integrity and location of the cement must be verified using technology capable of (1) evaluating cement quality radially and (2) identifying the location of channels to ensure ~~the likelihood of~~ that an unintended release of CO2 from the sequestration zone above the storage complex is not likely.” (RFVV1_126-14)

Comment: Typo needs to be corrected to change “and” to “an”.

“The timeline for review of the Emergency and Remedial Response Plan, no less than once every five years following its approval by the permitting agency, within one year following an~~d~~ AOR reevaluation, and within a prescribed period to be determined by CARB following any significant changes to the injection process or CCS project.” (RFVV1_126-19)

> **Agency Response:** Staff acknowledges and appreciates the commenters’ proposed revisions to the language of the Protocol. Staff agrees that the suggested revisions improve the clarity, accuracy, or concision of the CCS protocol. Therefore, staff modified the language accordingly, consistent with the changes suggested in the comments above. For example, in regard to comment GCCC1_14-10, which states, “Lateral migration out of the storage complex also can result in significant losses. Or specify lateral or vertical migration,” staff agrees that lateral migration can occur and that it may result in out-of-storage complex losses of CO_2. Therefore, staff modified the text of the Protocol as suggested by the commenter (…and ~~above~~ out of the storage complex). Or, in

regard to comment GCCC1_14-161, concerning microseismicity monitoring, staff agrees that geologic features like faults or fractures should be monitored in addition to wells. Thus, staff modified the Protocol to add microseismicity monitoring of "…[microseismic] activity within the vicinity of each injection well or near any discontinuities, faults, or fractures in the subsurface."

M-5.2. Multiple Comments: ***Comments that Partially Informed Revisions***

Comment: Comment to ARB: Operator should evaluate and describe the completeness of the well database. Some states better than others. Some may not be adequately complete to do this. So there should be an added box for this determination, box #2.

[Comment applies to Figure 6] (GCCC1_14-78)

Comment: "…Injection Period Monitoring Requirements…Testing and monitoring associated with CCS projects during the active life of the CCS project must include…"

… "site care and site closure that meets the requirements of subsection C.5.2(a)(2) and C.5.2(b)…"

"Table G.1. CCS project contribution to CCS project risk rating during injection phase of project based on risk types" (CATF1_100-12)

Comment: In some high quality sites, for example depleted gas reservoirs with no water drive, pressure will stabilize at an elevated pressure.

Plume will never stop. It will however be demonstrated to be changing in a predictable manner with no risk to performance.

"…the predicted timeframe in which pressure is expected to ~~decrease to pre- or close to pre-injection levels~~ stabilize…"

"…Post-Injection Site Care and Site Closure Plan ~~for a minimum of 100 years~~."

"…the pressure ~~front~~ is no longer increasing ~~in radius~~ (or is decreasing) and conforms to the model predictions pursuant to subsection C.2.4.1, and until CARB agrees a substantial trend in plume stabilization~~ity~~ has been demonstrated to the satisfaction of the Executive Officer ~~occurred~~."

"…~~As part of post-injection monitoring,~~ If required by the ~~and pursuant to the monitoring timeline as specified in the~~ Post-Injection Site Care and Closure Plan, the CCS Project Operator must in conformance with the specified timeline:

1. Conduct ~~quarterly~~ bottom-hole pressure tests in the monitoring wells in order to track the position of the pressure front:

2. Use appropriate best-practice methods to map the position of the free phase CO_2 plume and pressure front; and

3. Periodically update the ~~AOR~~ Storage Complex dilatation pursuant to subsection C.2.4 to determine if any corrective action is necessary ~~and to establish if~~ until a trend in ~~the~~ CO_2 plume ~~has stabilized~~ stability has been demonstrated.

4. Conduct leak detection checks at each well that is part of the CCS project, and in the near surface close to each plugged and abandoned well until the CO_2 plume ~~has~~ stabilization~~ed~~ trend is demonstrated to the satisfaction of the Executive Officer."

"…Once the trend in CO_2 plume stability has been demonstrated, all CCS project wells may be plugged and abandoned following subsection C.5.1(d)…"

~~"…1. Soil-gas and surface-air monitoring at, and within 10 ft of, the wellhead or well pad; and~~

~~2. Visual inspection of the wellhead and the land surface within a 100 ft radius of the wellhead or well pad.~~" (CATF1_100-17)

Comment: Page footer: "CCS Protocol Specific Purpose and Rational" should be "Rationale". (CCSPD1_106-39b)

Comment: "…*Injection Period Monitoring Requirements*…Testing and monitoring associated with CCS projects during the active life of the CCS project must include…" (CCSPD1_106-42)

Comment: "The CCS Project Operator must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of subsection C.5.2(a)(2) and C.5.2(b)." (CCSPD1_106-43)

Agency Response: Staff acknowledges the commenters' proposed revisions to the language in the Protocol. With respect to comment GCCC1_14-78, staff agrees that any historical records search should include an evaluation of the completeness of well database used in the search, and the text in subsection C.2.4.3.(c) of the Protocol was modified to add the requirement. Further clarification, or modification of Figure 5, is not necessary.

In response to comments CATF1_100-12 and CCSPD1_106-42, staff does not agree that "period" should be inserted in subsection C.4, as the intent is clear. Staff also does not agree with comment CATF1_100-12 that "during injection phase of project" needs to be added to the description of Table G.1, as liability remains on the operator during the post-injection site care and monitoring period for 50 years post-injection.

Staff agrees that adding "during the active life of the CCS project" will strengthen and clarify the language, and therefore, the text in subsection C.4.1.(a) was modified.

Regarding comment CATF1_100-17, staff acknowledges revisions proposed by the commenter. Staff agrees that the language in subsections C.5.2(a)(2)(A) and C.5.2(b)(3)(B) of the Protocol should be modified, and changed the language as recommended. Staff also agrees that the term "area of review," or "AOR," should be replaced with "storage complex," consistent with the changes to the definitions (please see Responses M-2.1 and M-2.5 in this chapter for further discussion of AOR) and changed the language as recommended. Finally, staff agrees that the specific language in 1 and 2 in subsection C.5.2(b)(3)(F) was potentially too prescriptive, and the language was subsequently removed. Please see Response M-13-2 in this chapter in regard to the modifications to subsection C.5.2(b). Staff addresses the 100-year monitoring requirement in Response M-6 in this chapter. Staff does not agree that any of the other proposed changes are necessary, as they do not add clarity to the Protocol.

M-5.3. Multiple Comments: *Editorial Comments Related to Risk and Appendix G*

Comment: "…~~and~~ to recalculate it every time the CCS project undergoes verification, and to recalculate it after injection has terminated and the Post-Injection Site Care and Site Closure Plan has been approved or reaffirmed." (CATF1_100-15)

Comment: "Table G.3. CCS project contribution to CCS project risk rating during post-injection phase of project based on risk types (with proposed changes marked relative to Table G.1)"

Risk type	**Risk category**	**Risk Rating Contribution**
Management	*Low Management Risk:* Demonstrated surface facility access control, e.g., injection site is fenced and well protected, and proven compliance history of highly competent management control of CCS project during injection phase.	~~1~~0%
	Higher Management Risk: Poor or no surface facility access control, e.g., injection site is open, or not fenced or protected and/or poor management control history during injection phase	2%
Site	*Low Site Risk:* ~~Selected site has more than two good quality confining layers above the sequestration zone and a dissipation interval below the sequestration zone~~ CCS Project Operator has submitted timely reports of GHG emissions reductions and monitoring results during injection phase. Reports have included measurements of relevant parameters sufficient to confirm permanent	~~1~~0%

	sequestration of CO_2. Data quality management has been sufficient to support quantification and verification of CO_2 sequestered with no indications of significant site risk.	
Site	*Medium Site Risk:* CCS Project Operator has submitted timely reports of GHG emissions reductions and monitoring results during injection phase. Reports have included measurements and analysis of relevant parameters sufficient to confirm that the ~~sequestration~~ permanent storage of CO_2 has been attained. Data quality management has been sufficient to support quantification and verification of CO_2 sequestered with only minor indications of site risk. *Higher Site Risk:* Project history suggests more than minor site risk over 100-year post-injection period. ~~Selected site meets the minimum site selection criteria but does not meet the above site criteria~~	~~2~~1% 2%
Well integrity	*Low Well Integrity Risk:* All wells for the CCS project meet USEPA class VI well or equivalent requirements with no indications of unmitigated well integrity issues during injection period.	~~1~~0%
	Higher Well Integrity Risk: The CCS project has wells that do not meet USEPA class VI well or equivalent requirements or has ~~show~~ indications of unmitigated well integrity issues during injection period	3%

(CATF1_100-16)

Comment: "*Appendix G. Determination of a CCS Project's Risk Rating for Determining its Risk of Atmospheric Leakage and Contribution to the LCFS Buffer Account*

This appendix is to be utilized to determine a CCS project's risk of atmospheric leakage pursuant to C.7(a)(3) and its corresponding duty to contribute to an LCFS Buffer Account." (CCSPD1_106-55)

Comment: "*The CCS Project Operator or Authorized Project Designee is required to determine the project's invalidation risk rating prior to submitting their application for CCS project certification, ~~and~~ to recalculate it every time the CCS project undergoes verification, and to recalculate it after injection has terminated and the Post-Injection Site Care and Site Closure Plan has been approved or re-affirmed.*" (CCSPD1_106-56)

Comment: "*Table G.1. CCS project contribution to CCS project risk rating during injection phase of project based on risk types*" (CCSPD1_106-57)

Comment: "*Table G.3. CCS project contribution to CCS project risk rating during post-injection phase of project based on risk types (with proposed changes marked relative to Table G.1)*"

Risk type	***Risk category***	***Risk Rating Contribution***
Management	*Low Management Risk:* Demonstrated surface facility access control, e.g., injection site is fenced and well protected, and proven compliance history of highly competent management control of CCS project during injection phase.	0~~1~~%
	Higher Management Risk: Poor or no surface facility access control, e.g., injection site is open, or not fenced or protected and/or poor management control history during injection phase.	2%
Site	*Low Site Risk*: CCS Project Operator has submitted timely reports of GHG emissions reductions and monitoring results during injection phase. Reports have included measurements of relevant parameters sufficient to confirm permanent~~that the~~ sequestration of CO_2. Data quality management has been sufficient to support quantification and verification of CO_2 sequestered with no indications of significant site risk. ~~Selected site has more than two good quality confining layers above the sequestration zone and a dissipation interval below the sequestration zone.~~	~~1~~0%

	Medium Site Risk: CCS Project Operator has submitted timely reports of GHG emissions reductions and monitoring results during injection phase. Reports have included measurements and analysis of relevant parameters sufficient to confirm that the ~~sequestration~~ permanent storage of CO_2 has been attained. Data quality management has been sufficient to support quantification and verification of CO_2 sequestered with only minor indications of site risk.	1~~2~~%
	Higher Site Risk: Project history suggests more than minor site risk over 100-year post-injection period. ~~Selected site meets the minimum site selection criteria but does not meet the above site criteria.~~	2%
Well integrity	*Low Well Integrity Risk:* All wells for the CCS project meet USEPA class VI well or equivalent requirements with no indications of unmitigated well integrity issues during injection period.	~~1~~0%
	Higher Well Integrity Risk: The CCS project has wells that do not meet USEPA class VI well or equivalent requirements or has ~~show~~ indications of unmitigated well integrity issues during injection period.	3%

(CCSPD1_106-58)

Agency Response: Staff appreciates the commenters' suggestions on risk calculations and categories. Staff does not agree that the suggested changes are necessary, nor do they align with the Protocol's overall philosophy of conservative risk assessment, as some of the proposed additions allow for high-risk provisions that staff believes should be avoided. Staff does not believe that low-risk should be valued at 0 percent. Furthermore, many of the proposed additions are subjective and may be difficult to analyze or apply fairly among projects. Staff included simple observational criteria that apply evenly across projects, and that increase ease of analysis. No modifications were made to the Protocol in response to these comments.

M-6. Multiple Comments: *100-Year Post-Injection Site Care*

Comment: Some flexibility should be built into this definition [site closure] so that improvements can be made as needed

"…~~and~~ unless otherwise ~~as~~…" (GCCC1_14-23)

Comment: Based on field experience and models, CARB may find that no additional work is needed to provided assurance of permanence of geologically-stored CO2.

"After injection is complete, the CCS Project Operator must continue to conduct monitoring as specified in this section and the Executive Officer-approved Post-Injection Site Care and Site Closure Plan for a minimum of 100 years or a modified period approved by the Executive Officer." (GCCC1_14-166)

Comment: 100 Year Operator Monitoring: This requirement is excessive and the duration basis is questionable. This burden on operators will likely discourage most EOR/CSS activity. (CRC1_35-2c)

Comment: More than 50 years post injection, which is the EPA Class VI statute, will likely be difficult to enforce, particularly for CCS projects located out-of-state. Unlike the forestry industry that requires regular maintenance to ensure growth and stability, geologically stored CO_2 showing stability (i.e., little or no movement) post injection requires no maintenance, as pressures will moderate and stability will improve over time. In addition, CCS projects typically involve numerous surface and pore space landowners. Surface access for monitoring and pore space agreements that extend multiple generations may be difficult to acquire and/or may go beyond out-of-state statues. Record keeping and data management may also be a challenge given the exponential advancement of technology over time. A project requirement of >100 years thus discourages rather than incentivizes projects, especially for fuel producers looking at markets that have the potential to change every few years. (RTE1_36-3)

Comment: Nonetheless, we question the practicality of a 100-year monitoring requirement. Class VI wells at the federal level target "only" 50 years. If CCS is to be an effective tool, implementing programs must be manageable. Perhaps a compromise would be to insist upon lengthy monitoring but limit the period of carbon credit invalidation. Perhaps ARB's proposed buffer account can come into play between the end of the invalidation period and the end of the monitoring period. As the saying goes, perfection should not be the enemy of the good. (CRF1_45-5)

Comment: In Section 5.2(b)(2), Post-injection Site Care and Monitoring, it is stated that:

> *After injection is complete, the CCS Project Operator must continue to conduct monitoring as specified in this section and the Executive Officer-approved Post-Injection Site Care and Site Closure Plan for a minimum of 100 years.*

Pursuant to the November 6, 2017 ARB CCS Workshop and ARB's rollout of the proposed 100-year Post-Injection Site Care (PISC) requirement, stakeholders have questioned the technical basis for secure geologic storage of CO_2 and have conclusively disputed its legal basis relative to the letter and spirit of the Global Warming Solutions Act (GWSA)[1] and the findings of Our Children's Earth Foundation v. ARB:

[1] AB 32 Chapter 488: Legislative Counsel's Digest: "The bill would require the state board to adopt rules and regulations in an open public process to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions, as specified."

ARB must build substantial evidentiary support for the 100-year provision, consider all relevant factors and demonstrate a rational connection between those factors, the provision, and the purposes of the Global Warming Solutions Act (GWSA). Deepika Nagabhushan – Clean Air Task Force.

The specification of 100 years appears to be an arbitrary time period, not based on anything physical, chemical, or project-related. We are advocates of risk- and performance-based monitoring. Arbitrary time periods with no rationale undermine the technical credibility of regulations. Jens Birkholzer – LBNL

The CCS technical community has not considered tools that could be used over 100 years post closure. It is not clear how 100 years of monitoring data can be used to further improve a robust model, or be effective in detecting previously unimagined failure. Sue Hovorka – University of Texas – Bureau of Economic Geology

Included in the quantification methodology (QM) post injection rationale was a linked[2] reference to the IPCC's Special Report on Land Use, Land Use Change, and Forestry (SR-LULUCF), apparently intended to be a technical justification for assigning 100 years PISC as "permanence" for CCS. The IPCC co-chairs of Working Group III, which produced the report, say very clearly in the preface the purpose and substance of the report that "The methodologies and the science assessed here are only intended for LULUCF, not geological sequestration." Indeed, the IPCC's Special Report appears to use 100 years simply as a convenient graphical timeframe (as basis to consistently compare GWPs) to illustrate examples of the net benefits of bio-sequestration, even with reversals ("ton-year" approach).

[2] http://www.ipcc.ch/ipccreports/sres/land_use/index.php?idp=74

Thus, by selecting 100 years as the definition of "permanence" for geological CO_2 sequestration, ARB has not only removed itself from a viable comparison of forestry vs. geo-sequestration (https://www.arb.ca.gov/fuels/lcfs/workshops/12042017_coalition.pdf, p. 29-30) but misunderstood the significance of a SP-LULUCF timeframe. Should ARB wish to use the IPCC work as an authoritative basis for regulating long-term CO_2 geological storage, a more logical guide, to start with, is their Special Report for CCS (SR-CCS), published in 2005, five years after the SR-LULUCF and prepared by experts in CO_2 storage and backed by a range of technical studies. Therein, one statement is particularly relevant (Technical Summary, p. 34; https://www.ipcc.ch/pdf/special-reports/srccs/srccs_technicalsummary.pdf):

"With regard to global risks, based on observations and analysis of current CO_2 storage sites, natural systems, engineering systems and models, the fraction retained in appropriately selected and managed reservoirs is very likely ["Very likely" is a probability of 90 to 99%] *to exceed 99% over 100 years, and is likely to exceed 99% over 1000 years. Similar fractions retained are likely for even longer periods of time, as the risk of leakage is expected to decrease over time as other mechanisms provide additional trapping."*

More recently, at the United Nations Framework Convention on Climate Change (UNFCCC) COP17/CMP meeting in Durban (2011), negotiators representing Parties to the Kyoto Protocol developed the Decision 10 of CMP7 (Annex B, page 28) of the Additional requirements for carbon dioxide capture and storage project activities under the clean development mechanism (CDM), states:

> *16. The monitoring of the geological storage site shall:*
>
> *(a) Begin before injection activities commence, to ensure adequate time for the collection of any required baseline data;*
>
> *(b) Be conducted at an appropriate frequency during and beyond the crediting period(s) of the proposed project activity;*
>
> *(c) Not be terminated earlier than 20 years after the end of the last crediting period of the CDM project activity or after the issuance of CERs has ceased, whichever occurs first;*
>
> *(d) Only be terminated if no seepage has been observed at any time in the past 10 years and if all available evidence from observations and modelling indicates that the stored carbon dioxide will be completely isolated from the atmosphere in the long term. This may be demonstrated through the following evidence:*
>
> > *(i) History matching confirms that there is agreement between the numerical modelling of the carbon dioxide plume distribution in the geological storage site and the monitored behavior of the carbon dioxide plume;*
> >
> > *(ii) Numerical modelling and observations confirm that no future seepage can be expected from the geological storage site.*

In summary, ARB's proposal for a minimum of 100 years PISC, is an arbitrary construction that has no basis in any CO_2 geological storage technical literature or expert opinion, the legal "precedent" ARB neither cites nor even provides a correct interpretation of the examples in the putative SR-LULUCF analog. This will essentially eliminate California's LCFS and Cap & Trade programs from consideration for deployment of CCS, despite the value of LCFS credits, and thus derail the state's climate goals.

There are viable alternatives that ARB could pursue:

1. Choose a shorter "arbitrary time" (consistent with other jurisdiction precedent) with provision for sound technical work as a basis for reducing this timeframe.
2. Develop an alternative longer-term stewardship program, managed by the state and supported by buffering accounts or another financial mechanism, that acknowledge the very low risk of substantial CO_2 leakage, particularly with time (e.g., IPCC SR-SCS "likely" and "very likely" scenarios) or even a "worst case" event.[3]

[3] e.g., Lindberg et al., 2017 (https://www.sciencedirect.com/science/article/pii/S1876610217321227)

(WSPA3_93-3)

Comment: But this 100-year post-injection site criteria is really problematic, if we really want to see some improvements, where we can actually utilize this to deploy CCS under the Low Carbon Fuel Standard program in an effective way. So all three of those can give us ome flexibility and sustainability as we go forward. (WSPA4_T48-7)

Comment: We do not question the efficacy of keeping CO_2 sequestered for 100 years under the proposed Protocol. We are confident that the very high degree of diligence imposed for selecting and operating sites appropriately will result in performance that far exceeds this standard. Along these lines, and synthesizing the best available technical information, the IPCC concluded in its Special Report on Carbon Dioxide Capture and Storage that:

> "based on observations and analysis of current CO_2 storage sites, natural systems, engineering systems and models, the fraction retained in appropriately selected and managed reservoirs is very likely to exceed 99% over 100 years, and is likely to exceed 99% over 1000 years. Similar fractions retained are likely for even longer periods of time, as the risk of leakage is expected to decrease over time as other mechanisms provide additional trapping."
>
> ['Very likely' is a probability of 90 to 99%]"[20]
>
> [20] IPCC, Special Report on CCS, Technical Summary.

The IPCC Guidance that CARB cites is focused on land use, land use change and forestry, and does not address the question of how long a sequestration site needs to be monitored in order to successfully demonstrate that the injected CO_2 will remain sequestered for at least 100 years. IPCC's comprehensive treatise on CCS (Special Report on CCS) also did not provide a definitive answer but that the duration of the monitoring needs to match the intended duration of the sequestration:

> "[...] The purpose of long-term monitoring is to identify movement of CO_2 that may lead to releases that could impact long-term storage security and safety, as well as trigger the need for remedial action. Long-term monitoring can be accomplished with the same suite of monitoring technologies used during the injection phase. However, at the present time, there are no established protocols for the kind of monitoring that will be required, by whom, for how long and with what purpose. Geological storage of CO_2 may persist over many millions of years. [...]
>
> Until long-term monitoring requirements are established (Stenhouse et al., 2005), it is not possible to evaluate which technology or combination of technologies for monitoring will be needed or desired. However, today's technology could be deployed to continue monitoring the location of the CO_2 plume over very long time periods with sufficient accuracy to assess the risk of the plume intersecting potential pathways, natural or human, out of the storage site into overlying zones. If CO_2 escapes from the primary storage reservoir with no prospect of remedial action to prevent leakage, technologies are available to monitor the consequent environmental impact on groundwater, soils, ecosystems and the atmosphere."

Since the time of writing of the IPCC Special Report on CCS (2005), different jurisdictions have adopted different approaches to long-term monitoring.

- The operator of the Gorgon Carbon Dioxide Injection Project can apply for site closure at some point after injection operations have ceased. The timeline for this is not specified but is based on the objective of the operator demonstrating the site is performing as expected and any residual risks are acceptably low and managed. At least 15 years following site closure, the site operator may apply for indemnity against certain third-party claims for loss or damage that might arise as a consequence of the injection operations in the longer term.
- The Quest Carbon Capture and Storage Project will be performing 10 years of post-injection monitoring. This was determined at the outset of injection based on reservoir modeling and site-specific risk assessment.
- Peterhead/Goldeneye had a performance-based period which could be six years or longer, based on surveys demonstrating containment of the stored CO_2 and no irregularities.
- The FutureGen project in Illinois accepted the 50-year default period in its USEPA Class VI permit.
- USEPA approved a modification of the default 50-year period to 10 years for the ADM Industrial Project in Illinois. This was done based on computational modeling to delineate the Area of Review; predictions of plume migration, pressure decline, and CO_2 trapping; site-specific geology; well construction; and the distance between the injection zone and the nearest Underground Sources of Drinking Water.
- The Occidental Petroleum operated Denver Unit and Hobbs Unit in the Permian Basin (Texas and New Mexico) are establishing the long-term containment of CO_2 in the San Andres formation, with a Specified Period of 10 years at the Denver Unit. At the conclusion of the Specified Period(s), Occidental Petroleum will submit a request for discontinuation of reporting when they can provide a demonstration that current monitoring and models show that the cumulative mass of CO_2 reported as sequestered during the Specified Period(s) are not expected to migrate in the future in a manner likely to result in surface leakage. It is expected that it will be possible to make this demonstration within 2-3 years after injection for the Specified Period(s) ceases and will be based upon predictive modeling supported by monitoring data.
- Under the American Carbon Registry's Methodology for Greenhouse Gas Emission Reductions from Carbon Capture and Storage Projects, the minimum post-injection monitoring period for CCS projects is set at 5 years. The duration of post-injection monitoring is to be extended beyond 5 years if no leakage cannot be assured at the end of the 5-year period. In this case, the Project Term is to be extended in two year increments and monitoring continued until no leakage is assured. The absence of atmospheric leakage is considered assured when it can be verified that no migration of injected CO_2 is detected across the

boundaries of the storage volume and the modeled failure scenarios all indicate that the CO_2 will remain contained within the storage volume.

In addition, the most current best practices literature uniformly points to a site-specific evaluation of the best methods to use in each case, taking into account variability in geology and other factors. Given the heavy emphasis on good site selection, risk mitigation and leakage prevention that underpins the entire Protocol, we believe that CARB's approach to post-injection monitoring should be modified for a number of reasons.

Given that projects will first need to be planned, financed, sited and operated, it will likely be several decades before any post-injection monitoring takes place. By that time, technology and practices are certain to have evolved beyond what is known or predictable today. The current approach locks in technologies and requirements that will lead to lower confidence, quality and environmental certainty than a tailored approach that is devised at the time when injection stops. Thus, we do not consider the proposed post-injection monitoring requirements necessarily to be conservative or environmentally protective.

We also note the added risk of any private entity defaulting on requirements that span a 100-year period. A preventative and protective approach should preempt such defaults, gaps in duty or enforcement actions by placing emphasis on proving with a higher degree of confidence earlier on that the sequestration performance will be achieved, and setting emergency funds aside for what we expect to be the rare cases when it is not.

Potential project developers also note the inherent difficulties in pursuing projects that carry with them ongoing duties that span an entire century, as well as liabilities tied to LCFS credit value that persist unless these duties are completed (we comment further on the latter below). (CCSPD1_106-16)

Comment: *"After injection is complete, the CCS Project Operator must continue to conduct monitoring as specified in this section and the Executive Officer-approved Post-Injection Site Care and Site Closure Plan ~~for a minimum of 100 years~~."* (CCSPD1_106-45)

Comment: *"As part of post-injection monitoring, if required by the ~~and pursuant to the monitoring timeline as specified in the~~ Post-Injection Site Care and Site Closure Plan, the CCS Project Operator must <u>in conformance with the specified timeline</u>:"* (CCSPD1_106-47)

Comment: We draw your attention to the draft post-injection site care (PISC) provision for carbon capture and sequestration (CCS) projects credited under the low carbon fuel standard (LCFS) program. This provision appears in Section 5.2(b)(2):

> *After injection is complete, the CCS Project Operator must continue to conduct monitoring as specified in this section and the Executive Officer-approved Post-Injection Site Care and Site Closure Plan for a minimum of 100 years*.

We are deeply concerned that such a requirement would severely limit, if not wholly preclude, the use of CCS in the state.

Initial discussions with staff suggest there is a serious misunderstanding regarding whether such a prohibitively-lengthy monitoring period is legally required by other ARB decisions. In particular, we believe there is confusion regarding whether the appellate court in *Our Children's Earth Foundation v. State Air Resources Board*, 234 Cal. App. 4th 870 (2015) or the Superior Court in Case No. CGC-12-519554 (Jan. 25, 2013) determined any applicable additionality or permanence criteria that could apply to CCS project monitoring. The trial court upheld the *additionality* of the urban forestry protocol on the basis that the Air Resources Board's (ARB's) protocol was amply conservative in assuring emissions reduction performance (in that instance, carbon sink value) significantly beyond business-as-usual forestry practices and thus was neither arbitrary nor capricious upon review. Neither the trial nor the appellate court, however, made any determination at all regarding the appropriate duration (e.g., permanence of storage) that would be required for any particular type of project and certainly did not address what monitoring period would be sufficient to assure that sequestered CO_2 would remain in the ground.

The appropriate question for selecting a post-injection monitoring period is what period the literature supports as sufficient to confirm that there will not be any significant leakage from the storage area. As other commenters have noted, that period is much, much shorter than 100 years. For example, the Obama EPA promulgated a 50-year default PISC and provided for shorter, alternative periods when supported by appropriate technical criteria.[1] In fact, the US EPA has granted at least three CCS projects shorter, 10-year, PISCs following appropriate technical reviews.[2] For a specific example, *see* the Illinois Industrial Carbon Capture and Sequestration Project #2: https://www.epa.gov/sites/production/files/2017-01/documents/adm_final_decision.pdf; at p.5.

[1] 75 Fed. Reg. 77230, 77300 (December 10, 2010). Section 146.93(b)(1) of EPA's Underground Injection Control Program – Criteria and Standards provides: "Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the Director-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the Director pursuant to requirements in paragraph (c) of this section, unless he/she makes a demonstration under (b)(2) of this section. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under (b)(2) of this section is submitted and approved by the Director."

Section 146.93(b)(2) provides the shorter post-injection monitoring alternative that EPA has approved in appropriate circumstances:

> *If the owner or operator can demonstrate to the satisfaction of the Director before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the Director may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where he or she has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs.*

[2] US EPA-approved projects granted 10-year PISC's include: Arthur Daniels Midland Industrial Project, Illinois; Occidental Petroleum Denver Unit, Texas; and the Occidental Petroleum Hobbs Unit, New Mexico.

On behalf of the Western States Petroleum Association and our other clients committed to the successful development of CCS, we urge the Board to direct the staff to continue to evaluate the appropriate monitoring period for CCS post-injection site care and to identify a reasonable period, consistent with the US EPA approach and available technical literature and expertise, both which assures storage integrity and provides a reasonable basis for financing and siting CCS projects. This critical design issue should not be finalized until there has been adequate further analysis. (LW1_110-1)

Comment: 100-year Post Injection Site Care (PISC) - CARB's selection of a 100-year PISC period for CCS project "permanence" has no basis in jurisdictional precedence or geologic / engineering reality. CARB attributes the 100-year term to the Intergovernmental Panel on Climate Change's (IPCC's) "Special Report on Land Use, Land-Use Change, and Forestry (SR-LULUCF). However, the SR-LULUCF does not establish nor recommend 100 years as an appropriate period to qualify for permanence. Instead, it simply used this number as a convenience-in-graphing exercise to show examples of net land use sequestration with reversals on a common GWP basis ("ton-year" concept). Also, the offsets court decision did not define permanence for forestry projects as 100 years, much less create a rationale to do so for CCS.[1] CCS and forestry are not similar sequestration methods by any criteria.[2] If CARB's intent is to seek guidance from IPCC authority in this case, then it should consider the specific findings of the IPCC "Special Report on CCS" (SR-CCS) publication (which was not used to approach the permanence issue).

[1] See Statement of Decision, Our Children's Earth Found, v. State Air Resources Board, Case No. CGC-12-519554 (Jan. 25, 2013); see also Our Children's Earth Found. v. State Air Resources Board, 234 Cal. App 4th 870 (2015)

[2] https://www.arb.ca.gov/fuels/lcfs/workshops/12042017_coalition.pdf, p. 29-32

(CHEVRON1_112-14)

Comment: A suitably risk-averse CCS protocol should balance the need to provide as much financial incentive to project developers who can accept the risk involved in deploying novel technology against the need to protect the public from potential risks due to improper storage or catastrophic release, as well as ensure that LCFS credits are granted in proportion to actual environmental benefits of the program. We support a requirement for 100 years of monitoring after injection ceases, though we accept the premise that as our understanding of CCS improves, this may turn out to be unnecessary. We suggest that rather than requiring a comprehensive 100-year monitoring plan to be agreed upon prior to project commencement, a project review be conducted when injection ceases to determine appropriate monitoring protocols using the best available methods at the time. Project developers should be obligated to demonstrate that carbon is being durably sequestered for a century after injection terminates, but the specific method used to make that determination can be made later, with the benefit of additional understanding. (NEXTGEN1_124-27)

Comment: My major objection to the CCS Protocol is that the CARB staff has elected to propose requiring that post injection site care continue for an absolute minimum period of 100 years. That proposal represents a radical departure from the overwhelming consensus of all other international, national and subnational governments and organizations that have adopted or recommended regulatory

frameworks for CCS. It also rejects the considered advice of CARB's own scientific experts as well as the other experts with extensive experience in the development and implementation of CCS pilot and demonstration projects and the oil and gas operators with the most experience designing and conducting carbon dioxide (CO_2) enhanced oil recovery (EOR) projects.

…

With respect to the closure requirement, no other entity has chosen to impose a 100 year post injection site care (PISC) requirement. Even the U.S. Environmental Protection Agency (EPA), which uses a default period of fifty years, has not imposed that as an absolute requirement. Instead, EPA allows geologic sequestration (GS) projects to demonstrate that an alternative post-injection site care timeframe of less than 50 years "is appropriate and ensures non-endangerment of USDWs." 40 CFR §146.93(c). Moreover, the 50 year PISC period is not absolute even in the absence of such a demonstration. Rather, closure can be approves whenever "the owner or operator can demonstrate to the satisfaction of the Director before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs." 40 CFR §146.93(b)(2). Likewise, the Director can extend the PISC if that demonstration cannot be made at the end of the 50 years.

…

Consistent with these requirements and recommendations, CARB should replace the 100 year absolute minimum PISC requirement with a performance standard to be satisfied by a demonstration that **"the injected CO_2 stream is not expected to migrate in the future in a manner likely to result in surface leakage."**

…

Other experts have echoed these comments in recommending deletion of the 100 year PISC requirement. I respectfully urge the Board to accept those recommendations and the detailed recommendations in my attached detailed comments. (RFVV1_126-1)

Comment: As explained further in the cover letter to these comments, the requirement for a minimum of 100 years from the cessation of CO_2 injection to the achievement of site closure does not make sense and is at odds with every other existing and recommended regulatory framework for CCS.

"'Site closure' means the point or date, ~~after at least 100 years and as~~ determined by the Executive Officer following the requirements under subsection C.5.2, at which point the CCS Project Operator is released from post-injection site care responsibilities." (RFVV1_126-6)

Comment: As noted by Dr. Sue Hovorka, "The 100 year duration of storage is assured by a robust calibrated model, based on long time scales typical of geologic processes. It is not conjectural.

"The CCS technical community has not considered tools that could be used over 100 years post closure. It is not clear how 100 years of monitoring data can be used to further improve a robust model, or be effective in detecting previously unimagined failure."[1/]

[1/] Comments [rv. 1] from S. D Hovorka, University of Texas at Austin, On Draft Accounting and Permanence Protocol for Carbon Capture and Geologic Sequestration under Low Carbon Full Standard.

See also the comments of Dr. Jens Birkholzer, Director Energy Geosciences Division, Berkeley Lab: "My experience is that a 100-year time period for monitoring well leakage is overly conservative and not supported by the current scientific knowledge of GCS and its potential risks."

"After injection is complete, the CCS Project Operator must continue to conduct monitoring as specified in this section and the Executive Officer-approved Post-Injection Site Care and Site Closure Plan ~~for a minimum of 100 years~~ based on a demonstration that the injected CO2 stream is not expected to migrate in the future in a manner likely to result in surface leakage." (RFVV1_126-17)

Comment: As noted by Dr. Sue Hovorka, "The 100 year duration of storage is assured by a robust calibrated model, based on long time scales typical of geologic processes. It is not conjectural.

"The CCS technical community has not considered tools that could be used over 100 years post closure. It is not clear how 100 years of monitoring data can be used to further improve a robust model, or be effective in detecting previously unimagined failure."[2/]

[2/] Comments [rv. 1] from S. D Hovorka, University of Texas at Austin, On Draft Accounting and Permanence Protocol for Carbon Capture and Geologic Sequestration under Low Carbon Full Standard.

See also the comments of Dr. Jens Birkholzer, Director Energy Geosciences Division, Berkeley Lab: "My experience is that a 100-year time period for monitoring well leakage is overly conservative and not supported by the current scientific knowledge of GCS and its potential risks."

"The CCS Project Operator must conduct leak detection checks at each well that is part of the CCS project, and in the near surface close to each plugged and abandoned well, every five years until the Executive Officer has authorized site closure ~~for 100 years after injection is complete, minus the time it takes for the CO2 plume to reach stability~~." (RFVV1_126-18)

Comment: The proposal, the CCS protocol locks in monitoring using today's technologies for a hundred years after injection stops. Now, we're confident that any project that complies with the comprehensive requirements of this carefully considered protocol will permanently trap CO2 for centuries or even more.

However, by the time these projects stop injecting, it is certain that technology and best practices will have yet evolved beyond what we can imagine today.

For example, a hundred years ago the first commercial airlines were established using wood and fabric airplanes. Just 50 years later we landed a man on the moon. We need a similar -- we need to retain a similar vision here.

We should build in flexibility on the technologies to be used and the necessary period of monitoring post injection. That would improve environmental performance in the future and make it more likely that operators will deploy carbon capture and storage projects that are much needed to reduce carbon footprint today. (NRDC2_T19-8)

Comment: There are, however, as others have mentioned earlier -- you know, challenges exist for deploying a project in the current rulemaking environment.

In order for a company like mine to access capital to deploy a CCS project that, you know, to date looks like it could potentially run into the hundreds of millions of dollars, you know, we need some assurances and further clarity from rulemaking.

The current protocol, as the previous speaker just alluded to, requires a hundred years of post-injection monitoring to ensure permanence. The financial burden associated with that monitoring maintaining the liability for a hundred years is a tall order for renewable fuel producer like our company.

As we're having discussions with the opportunity with financial institutions and investors, you know, we're all struggling to get our heads wrapped around the length of that obligation and the associated liabilities with it.

You know, we -- we know there are several jurisdictions that have addressed permanence with shorter time frames such as the 50-year protocol -- or, sorry -- the 50-year rule under -- in the EPA subpart RR. I believe it was already previously mentioned others like Alberta, Canada, have created entities that would assume the permanence liability after the site closure.

And additionally, we've gotten feedback that any kind of grandfathering or future assurances, you know, would help secure new capital for potential investors.

So we're asking the Board to direct the staff to examine -- keep continuing to examine those alternatives to the hundred-year permanence requirement and engage stakeholders in trying to find a more workable solution. (WE2_T34-3)

Comment: And in particular, the hundred-year provision in the protocol I know is something that has a history in California and there's reasons for why we've done it. We just wanted to try and promote some flexibility in how that is addressed.

…

But it would help to have a little more flexibility on how we're addressing the hundred-year issues in that protocol. (CONGESTOGA1_T39-2)

Comment: We do share the concerns over the 100-year monitoring requirement. You have heard from many others who also support CCS. I would like to highlight a couple of other concerns. (SHELL1_T50-5)

> **Agency Response:** Staff maintains that the 100-year post-injection monitoring requirement is both necessary and achievable. Moreover, staff believes that well-designed and implemented CCS projects can sequester carbon for at least 100 years and had, therefore, supported the adoption of a CCS protocol.
>
> In developing the Protocol, staff followed the requirements of AB 32, such that any regulations to reduce GHGs adopted by CARB ensure that the GHG emission reductions are permanent. AB 32 does not define what is considered as permanent, however, it is a fundamental policy question that must be answered for any carbon sequestration project.
>
> Following IPCC guidance,[53] CARB has chosen 100 years[54] as the standard for permanent reduction of CO_2 from all sequestration projects. In other words, carbon must be proven and verified to be sequestered for 100 years in order to be considered permanent emission avoidance, and thus equivalent to a non-reversible reduction in emissions (e.g. solar, increased efficiency, fuel switching, etc). This time frame is based on the carbon cycle model used to determine global warming potentials (GWP) and is a consistent with the 100 year time horizon CARB utilizes for its market based programs.
>
> CARB first applied the 100-year permanence requirement in its forestry offset protocol under the Cap-and-Trade program. The GHG emission benefits from forest offset and CCS projects face the same basic risk for the unintended release of sequestered carbon being released into the atmosphere. CARB acknowledges that the risks related to the reversal of credits via geologic sequestration are fundamentally different than those related to terrestrial sequestration. Therefore, CARB has incorporated stringent monitoring requirements for the early post-closure monitoring period (until the CO_2 plume stabilizes), and less stringent monitoring requirements after the plume stabilizes. Regardless of the differences in the risks for geologic versus terrestrial sequestration, on-the-ground verification of permanency must be established for the entire post-closure time period in order for operators to retain credits for GHG emission reductions. The CCS projects implemented for LCFS purposes will be the first regulatory-grade CCS projects to be recognized by the State. Taking a thoughtful and deliberative approach in the design of the Protocol and implementation of the program is essential to gain real-world experience and confirm theoretical expectations match real-world conditions. As experience is gained and new science emerges, staff will propose adjustments to the Protocol

[53] Land Use, Land-Use Change and Forestry. IPCC Webpage. Accessed: February 17, 2018. Available: http://www.ipcc.ch/ipccreports/sres/land_use/index.php?idp=74

[54] CARB also successfully defended this standard in court.

as necessary while still ensuring the reductions are real, permanent, verifiable, and enforceable.

Staff acknowledges the concern about deterring investment. However, similar claims were made when the 100-year permanence requirement was first proposed in the forestry offset protocol. At present, there are hundreds of forest carbon sequestration projects in compliance with the 100-year requirement and the market value of those compliance offsets is a magnitude less than the credits in the LCFS market. The goal of the Protocol is to maintain a scientifically rigorous and environmentally sound methodology that allows CCS to have a part in the market programs, but only if they can adhere to the same rules and standards as other sequestration technologies.

In regard to comments on liability, please see Response M-9.1 in this chapter.

M-7. Multiple Comments: *Non-Geologic Carbon Capture and Sequestration Projects*

Comment: In crafting rules to support this goal, however, we urge the Board to include mineralization of CO_2 as a form of CCS, including qualifying for credits under ARB's LCFS.

Comment: CCS is typically thought of as a series of complicated and energy intensive processes whereby waste carbon dioxide is extracted from the flue gases of large emission point sources, compressed to a supercritical state, transported to an appropriate disposal site, and pumped into deep geological formations for storage. Once in the ground, long term predictions about storage security are difficult and highly uncertain. In other words, continued monitoring is necessary as there remains the very real risk that the CO_2 might leak back into the atmosphere.

Geologists have long known, though, that in nature carbon dioxide is captured and permanently sequestered via the process of "CO_2 mineralization". When certain types of rocks are exposed to air and water, they undergo a chemical weathering reaction that transforms CO_2 into a stable carbon-based, 'carbonate' rock. The geochemistry of mineralization reactions is fairly well understood: metal ions (such as magnesium or calcium) react with carbonate and bicarbonate ions derived from carbon dioxide and water to mineralize as magnesium and calcium carbonate rocks (e.g. common limestone). Most of the carbon on Earth is in the form of carbonate minerals in carbonate rocks such as limestone. For example, this is how the cliffs of Dover were formed from calcareous marine phytoplantkon, and the way clams, oysters and other mollusks form their shells.[2] Thus, the process of CO_2 mineralization can be thought of a type of biomimicry in which carbon dioxide is permanently sequestered the same way that the natural world has captured this molecule for hundreds of millions of years.

[2] https://www.scientificamerican.com/article/how-are-seashells-created/

Significantly, according to the Intergovernmental Panel on Climate Change:

> The products of mineral carbonation are naturally occurring stable solids that would provide storage capacity on a geological time scale. Moreover, magnesium and calcium silicate deposits are sufficient to fix the CO_2 that could be produced from the combustion of all fossil fuels resources.[3]
>
> [3] IPCC, 2005 - Bert Metz, Ogunlade Davidson, Heleen de Coninck, Manuela Loos and Leo Meyer (Eds.). Cambridge University Press, UK. Pp 431. (http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf).

The National Energy Technology Laboratory put it this way:

> Carbon sequestration by reacting naturally occurring Mg and Ca containing minerals with CO_2 to form carbonates has many unique advantages. Most notably is the fact that carbonates have a lower energy state than CO_2, which is why mineral carbonation is thermodynamically favorable and occurs naturally (e.g., the weathering of rock over geologic time periods). Secondly, the raw materials such as magnesium based minerals are abundant. <u>Finally, the produced carbonates are unarguably stable and thus re-release of CO_2 into the atmosphere is not an issue.</u>[4]
>
> [4] https://www.netl.doe.gov/publications/proceedings/01/carbon_seq/6c1.pdf

In sum, carbon sequestration via mineralization (which is sometimes called carbonation) offers all of the benefits that the ARB has identified as being necessary to meet the goals of AB32, namely it is a real, permanent, additional, quantifiable, verifiable, and enforceable carbon capture process.

From a regulatory perspective, carbon mineralization offers the significant advantage over traditional CCS in that it is a much simpler task to quantify, verify and enforce the carbon capture process. And, it is truly permanent with <u>no monitoring</u> required. Once CO_2 is converted into limestone/dolomite, it is permanently sequestered.

In light of this potential to meaningfully and permanently impact the carbon intensity of fuels used in California, we ask that the Board:

1. Specifically include carbon mineralization as a technology available for LCFS credits.
2. Craft rules to ease the implementation of carbon mineralization as a means of achieving CCS. (BLUEPLANET1_34-2)

Comment: The eligibility for refinery investment project credits is unnecessarily narrow and excludes non-geological sequestration, such as through chemical conversion into durable goods such as plastic materials. It also restricts carbon capture to carbon dioxide and does not provide credit for the capture of carbon precursors to carbon dioxide, including carbon monoxide. We recommended to reword Section 95489(e)(1)(E)(1):

"Carbon oxide capture at refineries, or at hydrogen production facilities that supply hydrogen to refineries, and subsequent ~~geologic~~ sequestration;"

Other references to CO_2 specifically should be broadened to include carbon oxides generally, using "carbon" as a shorthand for this general class of molecules.

The eligibility for fuels produced using carbon capture and sequestration is unnecessarily narrow and excludes non-geological sequestration, such as through chemical conversion into durable goods including plastic materials. We recommended to reword the following Sections of 95490:

(a)(1)	*"(1) Alternative fuel producers, refineries, and oil and gas producers that capture carbon oxides on-site and ~~geologically~~ sequester carbon either on-site or off-site."*
(a)(2)	*"(2) An entity that employs direct air capture to remove carbon from the atmosphere and ~~geologically~~ sequester the carbon. If carbon derived from direct air capture is converted to fuels, it is not eligible for project-based CCS credits. However, applicants may apply for fuel pathway certification using the Tier 2 pathway application process as described in section 95488.7."*
(c)(2)(B)	"An engineering drawing(s) or process flow diagram(s) that illustrates the project and clearly identifies the system boundaries, relevant process equipment, mass flows, including the quantity of carbon injected into pipeline or delivered by other modes of transport for carbon injection <u>or sequestration by other means</u>, and energy flows necessary to calculate the CCS credit;"
(g)(2)	"Energy use and chemical use data for the carbon capture facility and carbon sequestration ~~injection~~ facility;"

(LANZATECH1_77-10)

> **Agency Response:** Please see Response M-3.4 in this chapter. Given the available time and resources, staff was unable to complete a comprehensive review and analysis regarding mineralization and chemical conversion CCS projects. Including these methods in the scope of the CCS Protocol would require further engagement with stakeholders, as well as internal research and review of methods and standards. Staff will continue to study this subject and consider whether to update the Protocol to include mineralization and chemical conversion CCS projects, if determined appropriate.

M-8. Multiple Comments: *Accounting Requirements*

M-8.1. *Accounting for Leakage*

Comment: In addition, we believe the accounting of any leakage from EOR operations used for CCS should include consideration total [*sic*] CO_2 stored underground, so that any invalidation of credits that occurs upon leakage from an EPR operation is calculated using a mass balance method for the CO_2 accounting (i.e. the percent fraction of the total injected CO_2 that is used for LCFS credits is applied to the total quantity leaked for the determination of LCFS credit invalidation.) (AJWIOGEN1_17-8).

Agency Response: The Accounting Requirements do use a mass balance approach and indirectly account for total CO_2 stored underground. The Accounting Requirements account for what was injected underground, what was produced and reinjected, as well as any leakage or other loss within the system.. Any CO_2 leakage that occurs in a given year must be appropriately quantified. If CO_2 leakage is not quantified via appropriate methods, it will result in credit invalidation. Therefore, the approach suggested by the stakeholder is similar to the approach in the CCS protocol and accomplishes the same goal, so a change to the protocol is not needed. In fact, the Accounting Requirements are more robust when considering all potential losses.

M-8.2. ***Simplifying Accounting***

Comment: *1. CARB should simplify the Accounting Requirements for CCS Projects under the LCFS to the measurement of CO2 injected into the geologic formation.*

Only CO2 injected into the geologic formation at the sequestration site would be used to generate LCFS credits and other lifecycle CCS project emissions are likely to be small in comparison to the quantity injected. As an alternative, and if deemed necessary, CCS project emissions could be evaluated one-time to determine the metric tons of CO2 Project Emissions per metric ton of CO2 Injected and deducted from each quantity of CO2 injected before credit generation. (FHR1_18-7)

Agency Response: Staff designed the Accounting Requirements to be comprehensive and robust, to ensure that GHG reductions achieved using CCS are real, additional, and verifiable, in line with the requirements of AB 32. The Accounting Requirements are designed for the LCFS program, which uses a life-cycle approach for all fuels and projects under the program. Moreover, CCS is an energy intensive process, and can result in considerable GHG emissions relative to the amount of CO_2 sequestered. Hence, it is important to consider life cycle emissions as part of the Accounting Requirements, for both consistency and to incentivize CCS projects that significantly reduce GHG emissions from the CO_2 capture and sequestration process.

The idea of one-time analysis of CO_2 emissions per ton of CO_2 injected may simplify the application process. However, the amount of CO_2 captured and injected, and related emissions, are is unlikely to remain constant from year to year, and the process will likely change over time. As a result, the assumption of linear CO_2 emissions per ton of CO_2 sequestered may not hold true for the duration of a particular CCS project. Therefore, the commenter's suggested approach is not appropriate. CCS projects are required to undergo annual verification, and calculating life cycle CO_2 emissions on annual basis may not require extra resources beyond what is required for annual verification.

M-8.3. *Simplifying CI Pathways*

Comment: As currently written, the CCS Protocol goes beyond established requirements for pathway approvals and CI determination; i.e., approved fuels do not require such prescriptive and stringent oversight by California ARB. For example, an ethanol facility need only provide process data that satisfies the quantification methodology (QM) to generate credits. Existing regulations at the local, state, and federal levels have been shown to be sufficient and are not further monitored by California ARB to ensure compliance, especially outside of California. In addition, systems within the fuel's production that are nebulous or highly variable, such as farming practices for biomass feedstocks, simply require formulas for calculation of CO_2 reductions with 60%-70% of resulting values allowed. A similar approach could be adopted for CI determination of CCS systems, allowing existing state and federal regulations to govern CCS management. (RTE1_36-2a)

> **Agency Response:** Staff acknowledges the commenter's concerns regarding pathway approvals. For accounting purposes, CCS related projects will either be considered under Tier 2 fuel pathways or project-based crediting provisions. In either instance, real-world operational data are required to accurately quantify GHG reductions. As more CCS projects come online, and CARB analyzes the typical ranges of operational parameters default or standardized values may be developed for certain parameters to simplify credit calculations.
>
> Please see Response M-3.3 in this chapter for staff's response to the comment concerning out-of-state CCS projects and jurisdictional requirements.

M-8.4. Multiple Comments: *Accounting for Off-Lease Migration*

Comment: Accounting is needed for off-lease migration. Not new to the industry, off-lease migration can be a significant problem for operators, as they may lose out-of-pattern oil or CO_2. Operators encountering this problem are routinely using conformance metrics (a form of monitoring) to track CO_2. Where CO_2 loss is a risk, water curtains can be set up (injected water blocking CO_2) and production at the boundary of a pattern or lease may, and discussions initiated with adjacent operators. Although the CO_2 may migrate outside the project boundary, it still may be largely stored if the adjacent operator is also recycling CO_2. Operators should report off-lease migration, and describe the estimated volumes, and methods to account for the CO_2, as well as steps taken to secure the migrated CO_2. Off-lease migration will typically terminate when injection ceases; therefore, the use of a water curtain may be an effective mitigation strategy during injection. The use of CO_2 conformance metrics be included in the tools recommended for monitoring CO_2 in EOR fields as they will help identify off-lease migration. (CATF1_100-4e)

Comment: Accounting is needed for out-of-pattern and off-lease migration. This is not new to the industry; migration can be a significant problem for EOR operators, as they may lose oil or valuable CO_2. Operators routinely use conformance metrics to track CO_2. Where CO_2 loss is a risk, water curtains (injected water blocking CO_2) and

production at the boundary of a pattern or lease may be used, and discussions initiated with adjacent operators. Although the CO_2 may migrate outside the project boundary, it still may be securely stored if the adjacent operator is also recycling CO_2. Operators should report off-lease migration, and describe the estimated volumes, and methods to account for the CO_2, as well as steps taken to secure the migrated CO_2. Off-lease migration will typically terminate when injection ceases; therefore, the use of a water curtain may be an effective mitigation strategy during injection. The use of CO_2 conformance metrics should be included in the tools recommended for monitoring CO_2 in EOR fields. (CCSPD1_106-10e)

> **Agency Response:** To ensure accurate estimates of the amount of CO_2 sequestered, the Accounting Requirements consider all potential losses of CO_2. Presently, it is difficult, if not impossible, to accurately verify that CO_2 that has migrated outside of the storage complex/lease is permanently sequestered. Assurances by the commenter that the CO_2 may be largely stored in certain conditions is inadequate to assure permanence of the migrated CO_2. Therefore, it is appropriate to consider any off-lease migration as leakage. As more CCS projects come online, and various monitoring technologies develop, methods may be developed to more accurately quantify off-lease migration. It is at the project operators' discretion to choose an appropriate mitigation strategy, such as water curtains.

M-8.5. Multiple Comments: *Fluid Measurement Locations*

Comment: The Protocol should require measuring fluid flow at the correct points to obtain high quality accounting. Currently the Protocol specifies measuring injection mass just before the injection well. In EOR this measuring point will include recycled CO_2 (CO_2 produced, separated, and reinjected) along with newly supplied CO_2. This should be avoided because it results in "double counting." Because of the possible complexity and unique surface processing during EOR, the Protocol should require the operator to identify and justify the locations and processes by which the best quality measurements can be obtained. At minimum this includes: 1) the new CO_2 supplied to the project attributed to source, 2) its allocation to injection wells, and 3) an explanation of recycled fluid accounting, including any losses or releases. (CATF1_100-4b)

Comment: The Protocol should require measuring fluid flow at the correct points to obtain high quality accounting. As written, the Protocol specifies measuring injection mass just before the injection well. In EOR this measuring point will include recycled CO_2 (CO_2 produced, separated, and reinjected) along with newly supplied CO_2. This should be avoided because it results in "double counting." Because of the possible complexity and unique surface processing during EOR, the Protocol should require the operator to identify and justify the locations and processes by which the best quality measurements can be obtained. At minimum this includes: 1) the new CO_2 supplied to the project attributed to source, 2) its allocation to injection wells, and 3) an explanation of recycled fluid accounting, including any losses or releases. (CCSPD1_106-10b)

Comment: Metering is currently required at the wellhead.[27] We recommend that CARB allow for central metering and allocation at the storage site to individual wells provided it can be shown that data obtained using this method is no less accurate, available or reliable.

[27] ATTACHMENT 1: CCS Protocol – C: Permanence, Page 80/175.

(CCSPD1_106-23)

Agency Response: The Accounting Requirements of the Protocol include newly injected (purchased or captured) CO_2 onlyfor the purpose of CCS credit calculations, as shown in Equation 1. Including recycled CO_2 would result in double counting, as recycled CO_2 was already considered when it was first injected. Therefore, metered data must reflect purchased (new) CO_2 only. These data are readily available for EOR operators.

In response to these comments, staff modified subsection C.4.3.1.2.(d)(1)(C) of the Protocol such that any measurements of fluid flow (or, metering) are no longer required to be performed at the wellhead. Rather, these measurements must be collected at some point downstream of transport, and upstream of any mixing between new and recycled CO_2. The exact point of fluid flow measurement within these bounds is left to the discretion of the project operator but must be conducted at a point before the recycled CO_2 is reinjected into the stream.

M-8.6. Multiple Comments: *Leakage Assumption and Detection Limits*

Comment: The proposed Protocol defines injected CO_2 to have leaked at the rate of half the sensitivity of the equipment employed to detect leaks.

Absent an indication from the monitoring program or otherwise, none of the injected CO_2 can justifiably be deemed to have escaped to atmosphere. The entire premise of the Permanence Protocol is to prevent any leakage. This is achieved through several layers of design and operational practices. For CO_2 to be leaking at levels that are below any given detection limit, all of those lines of defense need to have failed: a leakage pathway is required along with sufficient time for the CO_2 to reach the surface. Although this is possible, we consider it highly unlikely in practice, and see the de facto presumption of leakage under the detection threshold as undermining CARB's faith in its own regulations. The proposed provision effectively assigns a probability of 1 to leakage.

Moreover, despite all those lines of defense, CARB is proposing to collect Buffer Account contributions in order to take into account possible reversals – an approach that we support. Assuming a default rate of leakage is duplicative from a standpoint of incorporating conservatism into the accounting.

Finally, while we recognize that there is an inherent degree of imprecision in the flowmeters at the wellhead, these devices are routinely checked, calibrated and accepted for use in both commercial and regulatory applications. Any imprecisions may just as likely undercount as to overcount the quantity flowing through them.

For these reasons, CARB should not reduce the quantity of credits issued due to detection thresholds on the basis of conservatism. If a default rate of leakage is to be assumed on the basis of detection limits, CARB should make a determination not necessarily on the basis of equipment, but by considering the leak detection "methods" employed. (CCSPD1_106-21)

Comment: Assumption of Leakage Rates based on Monitoring Instrumentation Detection Limits – The QM includes the assumption that CO2 has leaked at a rate of half the sensitivity of leakage detection equipment and then reduces the amount of CO2 sequestered by this amount. It is inappropriate to assume leakage rates are a function of the sensitivity limits of measuring equipment. Some modern instrumentation has low enough detection limits to where the actual signal is well below the natural noise level. A more viable approach is to set appropriate detection limits relative to anticipated or determined noise level and follow a procedure to conduct further analysis to establish attribution for clear anomalies. (CHEVRON1_112-18)

> **Agency Response:** A key feature of the Accounting Requirements is that, for crediting purposes, any GHG emissions reductions achieved from CCS projects must be real, additional, and verifiable. Since GHG emissions reductions below the detection limit cannot be verified, ignoring potential leakage emissions below the detection limits could result in crediting of GHG emissions reductions that may not be real or additional. By assuming that CO_2 leakage occurs at half the detection limit, staff is erring on the side of caution as the quantity of CO_2 that leaks undetected is expected to be small, if it occurs.. This provision does provide an additional incentive for operators to use the best available detection methods, and to improve those methods. In other words, if staff's assumption of leakage at half the detection limit of the method is overly conservative (i.e., resulting in overestimates of leakage), Project Operators will be motivated to improve detection to reduce assumed leakage and increase credits generated.
>
> The assertion in comment CHEVRON1_112-18, that detection limits in some modern instrumentation are well below the level of natural noise, is reasonable. This comment has also suggested an approach which sets appropriate detection limits relative to the anticipated or measured noise level. Comment CCSPD1_106-21 suggests that detection limits should be determined on the basis of the methods used, not on the basis of any particular piece of equipment. Therefore, staff replaced the phrase "half the detection limit of the equipment" with "half the detection limit of the method" in subsection B.2.2.(e) of the Protocol.

M-8.7. Multiple Comments: *Miscellaneous Comments Related to the Accounting Requirements*

M-8.7a. **Comment:** Missing references to Vented CO2 and Fugitive CO2 in Equations 3 and 4.

Same is true for Figure 3. (GCCC1_14-27)

Agency Response: Venting and fugitive emissions are not required for Equations 3 and 4,. hence they are not shown in Figures 1 and 2 (formerly Figures 2 and 3 in the original version of the Protocol released on March 6, 2018).

M-8.7b. Comment: Please ignore the hash the PDF conversion made of equations. (GCCC1_14-28)

Agency Response: Staff appreciates the clarification.

M-8.7c. Comment: CO_2 that migrated outside the storage complex, e.g. where no confining system is present cannot be considered permanently stored. Such lost CO_2 must be subtracted from credits. This includes off lease migration for EOR, where CO_2 may be produced by adjacent conventional operator

"Added term = CO2 that has migrated outside the storage complex and cannot be qualified as permanently stored. (see section on options to increase the storage complex in 4.2.2)" (GCCC1_14-30)

Agency Response: In response to this comment, staff modified the Protocol to substitute "CO_2 leakage" for "atmospheric leakage" in Equations 5 and 6. CO_2 leakage now refers to both subsurface and atmospheric leakage, and now any leakage from the storage complex is included in the accounting.

M-8.7d. Comment: "Corrections should be applied if CO2 is impure" (GCCC1_14-178)

Agency Response: The volumetric emissions of CO_2 referred to in Appendix C of the Protocol are 100 percent CO_2 (excludes impurities), so there is no need to do a correction for impurities.

Comment: In section B.2.2(d), the text states:

"Annual GHG emissions from CO_2 transport must be calculated using Equation 4. CO_{2vent} and $CO_{2fugitive}$ in Equation 4 are zero if the CO_2 is of biogenic origin, such as from sugar fermentation, or derived from direct air capture."

However, the terms CO_{2vent} and $CO_{2fugitive}$ do not appear in Equation 4. Rather the terms appear in Equation 5. This should be corrected. (CCSPD1_106-31)

Agency Response: The sentence in question in subsection B.2.2.(d) of the Protocol ("CO_{2vent} and $CO_{2fugitive}$ in Equation 4 are zero if the CO_2 is of biogenic origin, such as from sugar fermentation, or derived from direct air capture.") is a residual sentence from the previous draft version of the Accounting Requirements in the Protocol, and should have been removed prior to publication. Staff deleted this sentence from the Protocol as part of the 1st 15-day changes.

M-9. *Buffer Account Allocation and Credit Invalidation*

M-9.1. *100 Years of Liability*

Comment: We believe the 100 year monitoring requirement is long, but may be manage-able. The critical issue is 100 year window on the invalidation of credits upon leakage. We urge CARB to consider a time limit to the window of the invalidation of the LCFS credits, and after a more modest period, the recourse for any leakage is the retirement of credits from buffer account (which receives LCFS credit annual payments akin to leakage insurance). (AJWIOGEN1_17-7)

> **Agency Response:** In response to the comments concerning 100 years of liability for leakage, staff modified the buffer account requirements in Section 95490(h), title 17, California Code of Regulations, such that operators are not liable for credit invalidation after the first 50 years of the post-injection phase, beyond those the project contributed to the buffer account. Operators must continue to monitor for leakage for the full 100 years.
>
> The reduced length of credit invalidation liability for the operator leads to increased reliance on the buffer account in the case of a leakage event after the 50 year post-injection phase. As such, staff modified the Protocol to increase the percentage of credits that projects must contribute during the project's active life. These changes bring the minimum Buffer Account contribution to 8 percent, which is in line with other CCS accounting requirements (between 5 to 10 percent). The changes, while conservative, are reasonable in order to cover the risk of reversal.

M-9.2. Multiple Comments: *Buffer Account Allocations*

Comment: As proposed, operators are expected to surrender between 3 and 12% of credits into the Buffer Account as insurance against potential leakage or credit invalidation and to update the risk rating every time the project goes under verification. ARB's proposed leakage risk ratings appear to be both arbitrary and excessive. WSPA requests that ARB provide a basis for the overall level of the risks and reassess the relative risk ratings across and within individual categories. (WSPA3_93-5)

Comment: Firstly, the volumes of CO2 that are proposed for impounding into buffer accounts seem excessive and well beyond what other jurisdictions are requiring. (SHELL1_T50-6)

> **Agency Response:** The risk of CO_2 leakage from a properly sited and managed CCS project is expected to be very low; however, the risk is never zero. Therefore, a percentage of a CCS project's LCFS credits must be contributed to the buffer account to cover the credit value of a potential CO_2 reversal. If CARB cannot recover all the required credits from the initial credit generator, CARB retains the flexibility to invalidate the credits held by an entity or entities other than the initial credit generator. This "buyer liability" policy is

fundamental to ensure the environmental integrity of the program butthe buffer account could help mitigate the invalidation risk for credit buyers.

A percentage of a CCS project's LCFS credits must be contributed to the buffer account pursuant to the Regulation. The percentage of the contribution is determined by the CCS project's risk rating, which is based on the potential for CO_2 leakage associated with different types of project-specific circumstances. The factors that contribute to a CCS project's risk rating are classified into 5 categories: financial, social, management, site, and well integrity. The magnitude of the contribution required for each type of risk reflects the relative significance of the risk, and the percentages fall within the range of reserve amounts in other carbon offset programs such as the Clean Development Mechanism (CDM), and American Carbon Registry (ACR).

The buffer account could be used to cover a large amount of credits for projects that experience a reversal following the 50-year-post-injection period, and so projects must therefore, surrender a higher number of credits (a minimum of 8 percent; see response to comment AJWIOGEN1_17-7 in Response M-9.1 in this chapter for staff's response concerning minimum contributions) than was originally proposed. The buffer account contributions must be conservative to account for the risk of potential credit invalidation if leakage does occur. As experience is gained through the implementation of CCS projects, staff may propose to revise the buffer account contributions in the future.

M-9.3. Multiple Comments: *Atmospheric Benefit of Sequestration Less Than 100 Years*

Comment: Some provisions in the proposed CCSP contemplate an invalidation of all credits generated upon specific occurrences, or do not rule out such a possibility. For example:

- If a well loses mechanical integrity and injection does not immediately cease.[4]
  [4] ATTACHMENT 1: CCS Protocol – C: Permanence Page 77/175.
- Section C.7.3, which states that "financial responsibility instrument(s) must be sufficient to address the potential endangerment of public health and the environment via atmospheric leakage."

Such an approach does not recognize the accrued benefits to the atmosphere from preventing a CO_2 emission in the first place and keeping it sequestered for a certain period of time, and goes against ARB's own stated justification for using a 100-year period as the definition for permanence, which identifies a partial atmospheric benefit over shorter periods as well.[5]

[5] Reference to IPCC guidance, ATTACHMENT 2: CCS Protocol Specific Purpose and Rational Page 170/175.

In cases where CO_2 has been verified to have remained sequestered for a given period in accordance to the requirements set forth in the CCSP (i.e., absent any error, fraud or other occurrence of non-compliance that was not dealt with according to the provisions

of the Protocol), ARB should recognize the atmospheric benefit of sequestration periods shorter than 100 years by applying an up-to-date calculation. (WSPA3_93-6)

Comment: Some provisions in the proposed Protocol contemplate an invalidation of *all* credits generated upon specific occurrences, or do not rule out such a possibility. For example:

- If a well loses mechanical integrity and injection does not immediately cease.[23]
  [23] ATTACHMENT 1: CCS Protocol – C: Permanence Page 77/175.
- Section C.7.3, which states that "financial responsibility instrument(s) must be sufficient to address the potential endangerment of public health and the environment via atmospheric leakage."

Such an approach does not recognize the accrued benefits to the atmosphere from preventing a CO_2 emission in the first place and keeping it sequestered for a certain period of time, and goes against CARB's own stated justification for using a 100-year period as the definition for permanence, which identifies a partial atmospheric benefit over shorter periods as well.[24]

[24] Reference to IPCC guidance, ATTACHMENT 2: CCS Protocol Specific Purpose and Rationale, Page 170/175.

<u>In cases where CO_2 has been verified to have remained sequestered for a given period in accordance to the requirements set forth in the Protocol (i.e. absent any error, fraud or other occurrence of non-compliance that was not dealt with according to the provisions of the Protocol), CARB should recognize the atmospheric benefit of sequestration periods shorter than 100 years by applying an up-to-date calculation.</u>

For example, as a current best practice, a time-adjusted warming potential[25] can be calculated for a project that injects 1MtCO_2/yr for 30 years and (1) retains all injected CO_2 permanently or (2) emits the entirety of the injected CO_2 70 years after injection begins.[26] In the former case of no release, the time-corrected CO_2e would be -26.6Mt over an analytical time horizon of 100 years. In the latter case of the total release, the time-corrected CO_2e over a 100-year analytical time horizon would be -14.9Mt. Hence, with a total release at 70yrs, the emissions/credit liability for the project should be capped at the difference of the two, i.e. 11.7MtCO_2e. Such a release scenario is not possible, but we present it for illustrative purposes.

[25] As described by Kendall, 2012, and using the author's provided calculator.

[26] Entering -1 in the calculator for years 0-29, and then entering either 0 or 30 for year 70.

(CCSPD1_106-18)

Comment: Some provisions in the proposed Protocol contemplate an invalidation of *all* credits generated upon specific occurrences, or do not rule out such a possibility. For example:

- If a well loses mechanical integrity and injection does not immediately cease.[4]
  [4] ATTACHMENT 1: CCS Protocol – C: Permanence Page 77/175.

- Section C.7.3, which states that "financial responsibility instrument(s) must be sufficient to address the potential endangerment of public health and the environment via atmospheric leakage."

Such an approach does not recognize the accrued benefits to the atmosphere from preventing a CO_2 emission in the first place and keeping it sequestered for a certain period of time, and goes against CARB's own stated justification for using a 100-year period as the definition for permanence, which identifies a partial atmospheric benefit over shorter periods as well.[5]

[5] Reference to IPCC guidance, ATTACHMENT 2: CCS Protocol Specific Purpose and Rationale, Page 170/175.

<u>In cases where CO_2 has been verified to have remained sequestered for a given period in accordance to the requirements set forth in the Protocol (i.e. absent any error, fraud or other occurrence of non-compliance that was not dealt with according to the provisions of the Protocol), CARB should recognize the atmospheric benefit of sequestration periods shorter than 100 years by applying an up-to-date calculation.</u>

For example, as a current best practice, a time-adjusted warming potential[6] can be calculated for a project that injects 1MtCO_2/yr for 30 years and (1) retains all injected CO_2 permanently or (2) emits the entirety of the injected CO_2 70 years after injection begins.[7] In the former case of no release, the time-corrected CO_2e would be -26.6Mt over an analytical time horizon of 100 years. In the latter case of the total release, the time-corrected CO_2e over a 100yr analytical time horizon would be -14.9Mt. Hence, with a total release at 70yrs, the emissions/credit liability for the project should be capped at the difference of the two, i.e. 11.7MtCO_2e. Such a release scenario is not possible, but we present it for illustrative purposes.

[6] As described by Kendall, 2012, and using the author's provided calculator.

[7] Entering -1 in the calculator for years 0-29, and then entering either 0 or 30 for year 70.

(CHEVRON1_112-20)

Comment: Section B.3(d)(1), provides:

> "All CCS projects must contribute a percentage of LCFS credits to the Buffer Account at the time of LCFS credit issuance by ARB. The CCS project's contribution to the Buffer Account is determined by a project-specific risk rating method, outlined in Appendix G. If CO_2 leakage unintentionally occurs at a CCS project, LCFS credits from the Buffer Account will be retired according to the provisions for invalidation in the LCFS."

In the course of continuous operations, CCS projects may have unintentional CO_2 leakage from various sources. This leakage is accounted for under Section C.2.2 and no LCFS credits generated for CO_2 that is not sequestered: fugitive or emissions from the subsurface to the atmosphere are reported under their own terms and no credits are issued for those quantities. The above language creates some ambiguity as to when and under what circumstances LCFS credits should be invalidated. Presumably, LCFS credits may be invalidated only where the CO_2 leakage exceeds the CO_2 sequestered in a given reporting period.

WSPA offers the following proposed alternative language in the CCSP:

> "All CCS projects must contribute a percentage of LCFS credits to the Buffer Account at the time of LCFS credit issuance by ARB. The CCS project's contribution to the Buffer Account is determined by a project-specific risk rating method, outlined in Appendix G.
>
> If CO_2 leakage unintentionally occurs at a CCS project, and the leakage exceeds the quantity of CO_2 stored by a CCS Project in a given reporting period, LCFS credits from the Buffer Account will be retired according to the provisions for invalidation in the LCFS."

Note that the suggested language is not intended in any way to interfere with operational requirements (relating to the cessation of injection or otherwise) for wells where leakage is detected or loss of mechanical integrity suspected. (WSPA3_93-7)

Comment: Section B.3(d)(1), provides:

"All CCS projects must contribute a percentage of LCFS credits to the Buffer Account at the time of LCFS credit issuance by ARB. The CCS project's contribution to the Buffer Account is determined by a project-specific risk rating method, outlined in Appendix G. If CO_2 leakage unintentionally occurs at a CCS project, LCFS credits from the Buffer Account will be retired according to the provisions for invalidation in the LCFS."

In the course of continuous operations, CCS projects may have unintentional CO_2 leakage from various sources. This leakage is accounted for under Section C.2.2 and no LCFS credits generated for CO_2 that is not sequestered: fugitive or emissions from the subsurface to the atmosphere are reported under their own terms and no credits are issued for those quantities. The above language creates some ambiguity as to when and under what circumstances LCFS credits should be invalidated. Presumably, LCFS credits may be invalidated only where the CO_2 leakage exceeds the CO_2 sequestered in a given reporting period.

<u>We offer the following proposed alternative language:</u>

> "All CCS projects must contribute a percentage of LCFS credits to the Buffer Account at the time of LCFS credit issuance by ARB. The CCS project's contribution to the Buffer Account is determined by a project-specific risk rating method, outlined in Appendix G.
>
> If CO_2 leakage unintentionally occurs at a CCS project, and the leakage exceeds the quantity of CO_2 stored by a CCS Project in a given reporting period, LCFS credits from the Buffer Account will be retired according to the provisions for invalidation in the LCFS."

We further clarify that the suggested language is not intended in any way to interfere with operational requirements (relating to the cessation of injection or otherwise) for

wells where leakage is detected or loss of mechanical integrity suspected. (CCSPD1_106-33)

Comment: Section B.3(d)(1), provides:

"All CCS projects must contribute a percentage of LCFS credits to the Buffer Account at the time of LCFS credit issuance by ARB. The CCS project's contribution to the Buffer Account is determined by a project-specific risk rating method, outlined in Appendix G. If CO2 leakage unintentionally occurs at a CCS project, LCFS credits from the Buffer Account will be retired according to the provisions for invalidation in the LCFS."

In the course of continuous operations, CCS projects may have unintentional CO2 leakage from various sources. This leakage is accounted for under Section C.2.2 and no LCFS credits generated for CO2 that is not sequestered: fugitive or emissions from the subsurface to the atmosphere are reported under their own terms and no credits are issued for those quantities. The above language creates some ambiguity as to when and under what circumstances LCFS credits should be invalidated. Presumably, LCFS credits may be invalidated only where the CO2 leakage exceeds the CO_2 sequestered in a given reporting period.

<u>We offer the following proposed alternative language:</u>

"All CCS projects must contribute a percentage of LCFS credits to the Buffer Account at the time of LCFS credit issuance by ARB. The CCS project's contribution to the Buffer Account is determined by a project-specific risk rating method, outlined in Appendix G.

If CO2 leakage unintentionally occurs at a CCS project, and the leakage exceeds the quantity of CO2 stored by a CCS Project in a given reporting period, LCFS credits from the Buffer Account will be retired according to the provisions for invalidation in the LCFS."

We further clarify that the suggested language is not intended in any way to interfere with operational requirements (relating to the cessation of injection or otherwise) for wells where leakage is detected or loss of mechanical integrity suspected. (CHEVRON1_112-21)

Comment: Similarly, CARB should require that project developers remain liable for the risk that CO_2 may be released from the project at some date after injection. In the event that a sequestration project loses containment of part or all of the sequestered CO_2, project developers should be liable for costs associated with remediating immediate environmental harms, preventing further loss of contained CO_2 and the damage to the climate from the release of carbon pollution. These risks may be addressed through provision of a suitable risk bond by the developer, or by claw-back provisions relating to LCFS credits in the event of release - though we would note that over the time scales relevant to CCS projects, claw-back provisions may be difficult to enforce in practice. Alternatively CARB may wish to consider holding part or all of the LCFS credits, or other carbon instruments, in escrow and transferring them to the project developer over the duration of the project on a schedule that reflects the time-adjusted value of the

sequestered carbon. Since CO_2 has a long atmospheric lifespan, delaying emissions reduces the impact of climate change over most time scales relevant to policy making, even if aggregate emissions remain the same. This is to say, it is better for the climate to release a ton of carbon in the future than it is today.[11] CARB may wish to base protocols relating to the release of sequestered CO_2 on the basis of rewarding project developers for the time carbon is sequestered, in the event of catastrophic release. Holding some LCFS credit value in escrow and distributing to project developers over time to reflect the value of the time sequestered carbon has spent underground reflects the risk of reversion, creates an incentive to maintain the project through its post-injection phase and ensures that developers will have a stream of revenue available for ongoing maintenance and monitoring.

[11] Kendall, A. (2012). Time-adjusted global warming potentials for LCA and carbon footprints. *International Journal of Life Cycle Assessment*, *17*(8), 1042–1049. http://doi.org/10.1007/s11367-012-0436-5

(NEXTGEN1_124-28)

> **Agency Response:** In response to these comments, staff modified the text in subsection B(3) to clarify buffer account contributions. It was never CARB's intention to prohibit the recalculation of a CCS project's risk rating at any time during or post-injection. Additionally, regarding the possibility of full invalidation of all credits generated from a project to date, CARB does not intend to invalidate any more credits than are equivalent to the amount of leakage that is determined to have occurred, unless we determine that the CCS project operator is not working in good faith to comply with the provisions. CARB does not intend to reduce invalidation of credits based on a "time adjusted value of the sequestered carbon" as this could potentially create a perverse incentive to be less concerned with protecting against leakage over time.

M-9.4. Multiple Comments: *Buffer Account and Financial Responsibility Instruments*

The following comments in this section are suggested line edits to the Protocol.

Comment: "(e) The buffer account balance of a CCS project is based on the CCS project's total contributions of credits to the buffer account made by the project during the period of injection reduced by any leakage from the project's storage complex pursuant to B.3(b).

(f) After injection has terminated and the CCS Project Operator has either received approval for an amended Post-Injection Site Care, and Site Closure Plan or demonstrated to the Executive Officer through monitoring data and modeling results that no amendment to the plan is needed, the Project Operator may use the project's buffer account balance as a qualifying financial responsibility instrument. The buffer account balance may only be used to satisfy the risk of atmospheric leakage of CO_2 as further described by C.7(a)(3). The CCS project's buffer account balance does not have any other purpose or value." (CATF1_100-10, CCSPD1_106-40)

Comment: "For purposes of this part, the CCS Project Operator must renew all financial instruments, if an instrument expires, for the entire term of the CCS project to

the extent that financial instrument remains necessary for the CCS Project Operator to fulfill the financial responsibilities as calculated for the applicable phase of the CCS project." (CATF1_100-14)

Comment: "For purposes of this part, the CCS Project Operator must renew all financial instruments, if an instrument expires, for the entire term of the CCS project to the extent that financial instrument remains necessary for the CCS Project Operator to fulfill the financial responsibilities as calculated for the applicable phase of the CCS project. The instrument may be automatically renewed as long as the CCS Project Operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument." (CCSPD1_106-54)

> **Agency Response:** Please see Response H-4 in this chapter for staff's response concerning the use of the buffer account for post-injection financial responsibility instruments.

M-10. Multiple Comments: *Financial Responsibility*

The following comments (CATF1_100-13, CCSPD1_106-19, and CCSPD1_106-53) are suggested line edits to the Protocol.

Comment: 4. On issues of Financial Responsibility found in C.7, we find the Protocol to be unduly rigid in some respects. Overall, the commencement of the project is the vantage point utilized for assessing the necessary resources. We understand that the need for this approach during the period of initial review and approval of the Permanence Certification. However, after the CCS project has an established operational history and compliance record, we think that the risk assessment should be revisited. We have several specific recommendations in this regard.

a. Regarding the risk of CO_2 leakage, the current language is insufficiently precise regarding the nature of the risk that must be covered by the financial responsibility instruments. We have suggested specific language to define this more clearly in the first sentence of C.7(a)(3).
b. Regarding the risk of atmospheric CO_2 leakage, we recommend that the credits that a project has deposited into the buffer pool of LCFS credits during the course of the injection period be taken into account. Using this approach, the account balance for a project would be calculated after the injection period using a new section B.3(e). The proposed approach would recognize all credits contributed and adjust the balance by any leakage that has occurred during the CCS project's active life.
c. Regarding financial responsibility in the post injection period, we are recommending that CARB recognize the buffer pool contributions that a specific project has made during its active life as a qualifying financial responsibility

instrument under C.7(a)3. This financial responsibility instrument could only be used to address the financial risk of atmospheric CO_2 leakage post injection.

d. We think that the Protocol would benefit from the establishment of a methodology to calculate the risk of atmospheric leakage of CO_2 for Financial Responsibility purposes. We are recommending that CARB utilize the same risk matrix approach that already exists in Table G.1 of Appendix G but apply it to the Financial responsibility section via C.7(a)(3). Post-injection, we recommend that this risk be recalculated based on project performance and compliance history. We recommend a new risk matrix approach as proposed in a new Table G.3. (CATF1_100-8)

Comment: "The financial responsibility instrument(s) must be sufficient to address the ~~potential endangerment of public health and environment via~~ risk of atmospheric leakage of CO_2, as determined by Appendix G. Post injection, the CCS project's buffer account balance may be utilized solely to address the atmospheric leakage risk pursuant to this section and B.3(f)."

"Appendix G. Determination of a CCS Project's Risk Rating for Determining its Risk of Atmospheric Leakage and Contribution to the LCFS Buffer Account

This appendix is to be utilized to determine a CCS project's risk of atmospheric leakage pursuant to C.7(a)(3) and its corresponding duty to contribute to an LCFS Buffer Account. CARB maintains ~~an~~ LCFS Buffer Accounts to insure against the risk of CO_2 leakage credited for sequestration and credit invalidation." (CATF1_100-13)

Comment: We perceive significant opportunities to introduce additional flexibility to the financial responsibility section without undermining CARB's authority to ensure that there are sufficient underlying assets to support project obligations and address risks. Section C.7(a)(3) appears open to varying interpretations.

Based on our review of other references to atmospheric leakage in the protocol, we think that this section should be revised to state, "The financial responsibility instrument(s) must be sufficient to address the risk of atmospheric leakage of CO_2." We also think that post-injection financial responsibility under C.7(a)(3) should be reduced by contributions to the buffer pool during the CCS project's active life. This is further explained below. (CCSPD1_106-19)

Comment: "The financial responsibility instrument(s) must be sufficient to address the risk of ~~potential endangerment of public health and the environment via~~ atmospheric leakage of CO_2 , as determined by Appendix G. Post injection, the CCS project's buffer account balance may be utilized solely to address the atmospheric leakage risk pursuant to this section and B.3(f)." (CCSPD1_106-53)

Agency Response: Please see Response H-4 in this chapter for staff's response to comments concerning project risk assessments, buffer account contributions, and post-injection financial responsibility instruments.

M-11. Multiple Comments: ***Technical Recommendations for CO_2-EOR***

Comment: While the Protocol states that it anticipates EOR, the Protocol as drafted takes an approach that is largely focused on saline storage, similar to the Environmental Protection Agency's Underground Injection Control Rule, Class VI. In order to better improve the security of CO_2 stored in oilfields, and, at the same time, encourage those projects, the design of the Protocol must take into account the inherent differences in pressure management during CO_2 injection for EOR projects that plan to store CO_2 rather than taking a saline project centric approach. (CATF1_100-4)

Comment: In order to better improve the security of CO_2 stored in oilfields, the design of the Protocol must take into account the inherent differences in pressure management during carbon dioxide injection for EOR projects that plan to store CO_2 rather than taking an approach that is tailored to saline projects. (CCSPD1_106-10)

Comment: EOR – Since the risk profile of CO2 EOR / storage is distinct due to the well-understood geologic model for EOR reservoir dynamics (most notably inherent pressure control and limited AoR), it should be treated differently from saline storage. The focus for EOR should be on wells and the potential for "leakage" via cross lease migration and subsequent production (essentially an accounting exercise). (CHEVRON1_112-19)

> **Agency Response:** Staff appreciates the commenters' expertise and feedback on the addition of EOR-related provisions. The Protocol's primary objective is to ensure real, permanent reductions from CCS and all projects should be held to rigorous standards to ensure proper accounting with appropriate site selection and monitoring. While provisions allow flexibility for different project types, all must be held to the same criteria. Staff also appreciates the specific recommendations associated with comments CCSPD1_106-10a through CCSPD1_106-10f, which are addressed in the response indicated in the table below:

Comment Number	FSOR Response
CCSPD1_106-10a	M-2.1.
CCSPD1_106-10b	M-8.5.
CCSPD1_106-10c	M-12.7.
CCSPD1_106-10d	M-12.4.
CCSPD1_106-10e	M-8.4.
CCSPD1_106-10f	M-12.6.

Please see Response M-8.4 in this chapter for staff's response to comment CHEVRON_112-19 discussing accounting for off-lease migration.

M-12. Multiple Comments: *Site Characterization*

M-12.1. Modeling Codes: *Commercial versus Open Source*

Comment: We suggest that the Protocol allow for use of commercial codes as long as these are shown to be sufficient by comparison with open source code. Commercial codes can under some conditions provide better and faster numerical solutions. In some cases, updated codes may only be available commercially. This has been evident in situations involving complex miscible fluids. Transparency should be provided by providing complete documentation of the model inputs, calibration, and workflow. (CCSPD1_106-25)

Agency Response: In response to this comment, as well as others from the 1st 15-Day comment period (please see Response M-8.1 in Chapter V), staff modified subsection C.2.4.1.(a)(2) of the Protocol to add a commercial option for the code(s) used to delineate the storage complex and model the plume extent. The additional option includes a set of requirements that allow operators to use proprietary, commercially available software. New requirements for model code(s) include peer-review, CARB access, and third-party validation.

M-12.2. *Description of "All" Geologic Structures*

Comment: The proposed Protocol requires "[a] full description of all geologic structures, including faults and fractures, which intersect the storage complex and all data relevant to assessing the transmissivity of these features". Faults and fractures can vary from very large to micro-scale, and a strict interpretation of this provision renders the task impossible. We recommend that the Protocol require the project operator to describe such features which affect leakage risk, along with a justification of the scope of the description. (CCSPD1_106-26)

Agency Response: Staff agrees that a description of "all" geologic structures could be unrealistically large in number, and CARB staff is concerned only with structures that may affect permanence. In response, staff removed "all geologic structures" and replaced the phrase with "significant geologic structures" in subsection C.2.3.(a)(6) of the Protocol.

M-12.3. *Identification of all Groundwater Wells*

Comment: The proposed Protocol requires that all water wells are listed, described and located. In some jurisdictions, private drilling of shallow groundwater wells may be unregulated. State- or county-maintained records of existing wells may also not exist. CARB should consider the requirement against this background, consulting with the State Water Resources Control Board and the Department of Water Resources in California, and also consider out-of-state jurisdictions. (CCSPD1_106-27)

Agency Response: Staff disagrees with the commenter that all water wells need not be listed, described, or located. Provided the operator obtains the proper Class II or Class VI permit, or equivalent, the operator should already have a database of this information. Proper site selection requires a complete search for all ground penetrations within the surface area of the storage complex, which includes groundwater wells. Staff did not modify the language of the Protocol in response to this comment.

M-12.4. Multiple Comments: *Reliance on Well Database Records for Corrective Action at Legacy Wells*

Comment: Section C.2.4.3(c) states that "CCS Project Operators must perform corrective action on all wells within the AOR that are deemed to need corrective action, including all wells that penetrate the storage complex and are determined to have been plugged and abandoned in a manner such that they could serve as a conduit for fluid movement into the shallower subsurface, prior to the commencement of injection." Furthermore, Figure 6 displays a flow chart. One box states "Do records indicate the wells are plugged in a manner that will prevent carbon dioxide plume of formation fluid migration…"

<u>CARB should clarify to what extent existing records can be relied upon at state and federal regulatory levels in determining the basis for corrective action. We note that the quality and reliability of records varies.</u> (CCSPD1_106-36)

Comment: A principal risk in oilfields is legacy well integrity. The Protocol as proposed requires substantial due diligence to identify existing wells in the project area, however, it should be strengthened by requiring a description of the completeness of any well databases relied upon for this analysis, as completeness may vary from state to state and field to field. (CCSPD1_106-10d)

Comment: A principal risk in oilfields is legacy well integrity. The Protocol currently requires substantial due diligence to identify oil wells in the project area, however, it could be strengthened by requiring a description of the completeness of well database, as completeness may vary from state to state. (CATF1_100-4d)

Agency Response: Staff agrees that a description of the completeness of the well database(s) relied upon should be included in the Corrective Action Plan and the determination of corrective action. In response, staff modified subsection C.2.4.3.(c) of the Protocol to include this provision.

M-12.5. *Confining Layers and Dissipation Interval*

Comment: Confinement System – CARB has recognized that CCS must be treated in a site-specific manner. However, the QM's confining layer requirement does not meet this criterion. CARB is proposing requiring two sets of confining layers to ensure containment of injected CO_2 or displaced fluids. In addition, there are specific geomechanical testing criteria, notably for ductility (inverse of brittleness), that are favored. All things being equal, two seals are better than one but given the complexity

of geologic systems, confinement should be considered holistically rather than relying on a numerical treatment of rock layers and their specific physical properties. For example, a seal rock that is considered "brittle" might be expected to propagate fractures further and for these fractures to remain open. However, it may, under various tectonically- favorable stress regimes, behave differently. Widely used mechanical earth models (MEMs) consider rock properties and multi-scale stresses to more reliably predict containment performance during injection. Requiring multiple confining layers that are ductile will limit consideration of suitable geologic storage venues (particularly older, deeper shales and other common lithologies of all ages such as marls and carbonates). (CHEVRON1_112-17)

> **Agency Response:** Please see Response M-2.2 in this chapter for staff's response concerning confining layers and dissipation intervals.

M-12.6. *Well Testing and Logging: Using Existing Data*

Comment: The proposed Protocol includes well logging and core analysis that can be collected when advancing new wells. Section 2.3.1(d) provides:

- For a CO_2 injection well to be transitioned from a pre-existing injection, monitoring, stratigraphic test, or production well, the testing and logging information required by subsections C.2.3.1(e) through C.2.3.1(j) can be provided from previous and ongoing testing and monitoring of the formation and from well tests and logs conducted during the previous use of the well.

Subsections C.2.3.1(e) through (j), include comprehensive well logging and core analysis requirements.

- Existing CO_2-EOR projects may not have all the information the protocol seeks for all of its injection wells. However, a CO_2-EOR project may have acquired data during its operating history that provides equivalent or better quality information than that intended to be collected through the well logging and core analysis provisions, for example verification of the depth, thickness, porosity, permeability, lithology, and salinity of all relevant geologic formations.
- We suggest alternative language that permits an applicant to substitute data of equivalent or better quality from other sources to verify geologic conditions.

For existing CO_2-EOR wells and where a CO_2 injection well will be transitioned from a pre-existing injection, monitoring, stratigraphic test, or production well, data such as the testing and logging information required by subsections C.2.3.1(e) through C.2.3.1(j) can be provided from previous, proximate, ongoing testing and monitoring of the formation and from well tests and logs conducted during the previous use of the well. This should be allowed provided the data is of equivalent or better quality. (CCSPD1_106-10f)

> **Agency Response:** Staff agrees that for existing CCS projects, historical data should be allowed to be submitted in lieu of the testing and logging requirements

for new wells. It was never CARB's intention to prohibit the submission of historical data, and thus, staff modified subsection C.2.3.1.(d) of the Protocol (see Protocol released on August 13, 2018) to explicitly add a provision that allows for this, provided the data quality is equivalent to or better than that required for new wells.

M-12.7. Multiple Comments: *Seal Properties for Oilfields*

Comment: Because seal quality of a hydrocarbon reservoir is relatively well known compared to a saline formation, a best practice for EOR is to focus on history matching and analyzing past production and to expend less effort in collecting data about the seal properties. This will require, instead, that data be collected to produce a model that can be used to define the storage complex that will accept and retain CO_2. (CATF1_100-4c)

Comment: Because seal quality of a hydrocarbon reservoir is relatively well known compared to a saline formation, a best practice for EOR is to focus on analyzing past production to predict reservoir response to injection, as this will be more informative than collecting substantial additional data about the seal properties. This will require, instead, that data be collected to produce a model that can be used to define the storage complex that will accept and retain CO_2. (CCSPD1_106-10c)

Agency Response: Staff acknowledges that there are differences in the way that seal properties are characterized between EOR projects and saline storage projects. Staff modified subsection C.2.3.1.(d) of the Protocol such that the submission of past production data, or any other data previously collected to produce models that define the storage complex is allowed (please see Response M-12.6 in this chapter). However, because much of the data the Protocol requires should have already been collected at some time in the past and this data is necessary for proper model development, staff retained the aforementioned data provisions.

M-12.8. Multiple Comments: *Under-Pressured Reservoirs*

Comment: This requirement unnecessarily eliminates under pressured depleted gas reservoirs. These sites can accept CO_2 but at low pressure.

"…supercritical state <u>(underpressured depleted gas reservoirs are exempt from the supercritical phase requirement</u>…" (GCCC1_14-37)

Comment: Note that this requirement ["it will exist as a supercritical phase"] eliminates depleted gas reservoirs, which are underpressured. Depleted gas reservoirs are one of the safest and most desirable storage settings, and have been proposed in California. (GCCC1_14-180)

Agency Response: Reasonable restrictions on the depth of injection are required, not only to ensure permanence, but also to allay the concerns of the public regarding the risk of CO_2 leakage to the atmosphere. Staff included the

requirement that the CO_2 be supercritical at depth in order to avoid requiring only a minimum depth for injection, as the depth at which CO_2 becomes supercritical will vary depending on geologic setting. The supercritical requirement strengthens the requirements for permanence. As projects come online under the Protocol, and various monitoring technologies develop, this requirement may be reevaluated.

M-13. Multiple Comments: *Post-Injection Site Care*

M-13.1. Post-Injection Monitoring Approach

Comment: We understand the proposed approach on post-injection monitoring to have its roots in CARB's forestry protocol. In our Dec 4, 2017, stakeholder feedback to CARB on the Draft CCS Accounting and Permanence Protocol and on Draft Regulatory Amendments to the Low Carbon Fuel Standard, we presented in great detail the fundamental differences between carbon sequestration through forestry and through CCS. We reiterate the main differences in the following table:

Characteristic	***Forestry***	***CCS***
Nature of trapping	Living organism.	Geologic, engineered.
Time frame	Typically decades or centuries. Oldest known tree was a bristlecone pine at ~4,845yrs old (very rare).	Geologic formations have trapped fluids for millions to hundreds of millions of years.[10]
Leakage mechanisms	Tree loss through felling, disease, ageing, fire, environmental factors (weather, climate).	Geologic leakage: existing faults or fractures, induced fracturing of rock. Leakage through wells.
Nature and magnitude of possible leakage	From trivial to catastrophic/total. Release from forest loss can be effective in returning a high percentage of the trapped CO_2 to the atmosphere.	Small for both types of leakage. With the exception of very specific settings (e.g. volcanic), which would be readily avoided, leakage through faults has been studied and show to be very small/slow. Rate of leakage through wells is also limited,[11] and even smaller after wells have been plugged and abandoned.[12] The most severe events, surface blowouts, still

		produced limited leakage and are self-mitigating.[13]
Is sequestration performance predictable?	Overall, no. Fires, diseases or breaches of law/contract cannot be modeled or predicted. Health can to a limited degree.	Yes. Sophisticated software models the CO_2 plume and is continually updated with observation data from operations. Well leakage of the course of many decades has been shown to be an occurrence, but it is limited to a very small percentage of wells, and is small in volume and correctable.[14,15,16,17]
Is leakage preventable?	Only to some degree. Even if the land is successfully set aside and guarded, natural causes may still cause leakage (loss of trees).	Almost entirely. The entire premise of a CCS project is to select, operate and decommission a site with the goal of minimizing risk. Regulations have been found to be one of the primary determinates of the likelihood of well leakage.[18] The Permanence Protocol imposes very specific requirements in order to achieve this.
How does the risk of leakage evolve over time?	Hard to predict. Human, climatic and other factors may increase or decrease risk. No default trend, but some reason for concern (land use change, climate change).	Geologic trapping mechanisms (dissolution trapping, residual trapping and mineralization) are magnified over time. Creep and slough tend to collapse wellbores and exhibit self-healing properties. These factors combine to create an ever-decreasing risk profile.

[10] IPCC, Special Report on CCS.

[11] Hovorka, 2009. A production test months after the end of injection was unable to produce significant CO_2, demonstrating that it was effectively trapped because saturation had decreased to near-residual and relative permeability to CO_2 was near zero.

[12] See Mordick, B., Peridas, G., 2017, Ch.7.

[13] Lindberg et al., 2016. For the case of a surface well blowout that vented for 112 days, the authors state that "While 2.8% of the stored gas was lost at the Aliso Canyon leak, the corresponding loss from a CO2 well if the

facility was used for CO2 storage would be 0.37%. Due to the high density of CO2, the well pressure at the rupture was less than half than for CO2 compared to gas, which will make remediation easier." This represents an event that is very unlikely, and severe in its magnitude and duration.

[14] Celia et al., 2011.

[15] Kang et al., 2014.

[16] Porse et al, 2014 assess the risk to be on the order of 10^{-3}, with the relevant sample space being Railroad Commission districts in Texas. Others assess the risk to be two orders of magnitude lower (10^{-5}) based on offshore wells in the UK, highlighting that location and regulation can play an important part in mitigating risks. See, for example, HSE, 2008 (RR671) and HSE, 2008 (RR605).

[17] Pawar et al., 2009.

[18] Bachu & Watson, 2007 (presentation) and SPE paper.

(CCSPD1_106-15)

Agency Response: Please see Response M-6 of this chapter for staff's response outlining the reasoning behind modeling the CCS Protocol's post injection monitoring approach.

M-13.2. *Concerns with Post-Injection Prescriptive Monitoring Requirements*

Comment: CARB should allow for a possible reevaluation of post-closure monitoring requirements, including but not limited to duration and methods used, once injection is complete. This will not only be done with the benefit of the extensive site data that have been collected during the injection phase, but will also make possible an assessment of remaining risk and needs on the basis of the technology and techniques of the time - not that of several decades prior. This will contribute further to sequestration integrity and performance, reducing the risk of any leakage even further.

The protocol as proposed is already structured in an appropriate manner to enable revision of the original Post-Injection Site Care and Site Closure Plan after injection has ceased. This is mandated by C.5.2(a)(3). Recognizing that the Executive Officer will retain full authority and oversight over the scope of the monitoring at this time, we recommend that mandatory provisions contained in C.5.2(a) and C.5.2(b) be more limited. While all of these monitoring tools should be available for the Executive Officer to impose based on site conditions and experience, the current list is more limiting than is warranted for every project. We are certain that the state of sequestration science, and the best available technologies and best practices will expand in the coming decades. Prescribing tools now is worse both from an environmental and a project development and operation standpoint. We therefore recommend that CARB not build in mandatory regulatory language except to the extent necessary. An appendix below contains a redline with our specific suggestions in this area.

Regarding the default provisions as currently proposed that would apply prior to a revision of post-closure monitoring requirements once injection is complete, we make the following recommendations:

- As we explain at length in our Dec 4, 2017, stakeholder feedback to CARB on the Draft CCS Accounting and Permanence Protocol and on Draft Regulatory Amendments to the Low Carbon Fuel Standard, soil gas monitoring is already known to suffer from inherent limitations. If the post-injection monitoring section

is to continue to prescribe types of method, the reference to soil gas[21] should be changed to "near surface" monitoring, to allow for other, more effective, techniques that could detect CO_2 in the shallow subsurface. This is further detailed above.

[21] ATTACHMENT 1: CCS Protocol – C: Permanence, Page 102/175

- Similarly, the requirement to perform visual wellhead checks[22] should be revised to allow for more effective alternatives such as automated methods or remote sensing to confirm wellhead integrity and detect any leaks there.

[22] ATTACHMENT 1: CCS Protocol – C: Permanence, Page 103/175

(CCSPD1_106-17)

Agency Response: In response to the comment that concerns allowing reevaluation of the post-closure monitoring plan, staff notes that this is already a requirement of the Protocol. Subsection C.5.2(a)(3) states that, "Upon injection completion, the CCS Project Operator must either submit an amended Post-Injection Site Care and Site Closure Plan or demonstrate to the Executive Officer through monitoring data and modeling results that no amendment to the plan is needed." Furthermore, staff notes that the operator is allowed to revise the post-injection monitoring plan at any time during the life of the CCS project. Therefore, this comment did not warrant any modifications to the Protocol.

In response to the comments concerning prescriptive monitoring methods, including similar comments from the 1st 15-day comment period (see comments in section M-4.2 and M-10.8 in Chapter V and M-4.2 in Chapter VI), staff conducted an extensive re-write of subsection C.5.2(b). The revisions include the removal of specific prescriptive requirements, such as soil-gas and surface-air monitoring. Staff replaced the prescriptive requirements with performance-based requirements, and added language that allows for the use of aerial monitoring methods. For further discussion of prescriptive versus performance-based requirements, see Responses M-3.2 and M-6 in this chapter. CARB will continue to monitor technology development and make appropriate changes to the Protocol as necessary and as outlined in Resolution 18-34.

M-13.3. *Well Plugging and Abandonment Plan*

Comment: Section 5.1 requires a well plugging and abandonment plan be developed and submitted with the Sequestration Site Certification. The plan must be updated as needed throughout the life of the project. We agree that ensuring wells are properly plugged and abandoned is an important component of the protocol and will help ensure the long term integrity of the CCS Project. The demonstration, however, should not require a detailed plugging and abandonment plan since changing technology and conditions may well render any plan prepared 100 years or more before closure, obsolete. <u>Rather, the protocol should ensure that the project operator at the time of closure develop a detailed plan compliant with the best management practices, technologies and materials of that time, provided these are better than at the time of project certification, or require a performance standard to be met.</u> (CCSPD1_106-34)

Agency Response: Staff does not agree that a detailed plugging and abandonment plan is not necessary prior to closure. Operators should have these plans prepared in advance of any possible well plugging event, including events in which a well needs to be plugged and abandoned prior to its planned closure if, for instance, a well fails a mechanical integrity test and must be abandoned before CO_2 leaks to the atmosphere. Staff acknowledges that technology and plans will change over time, which is why the plugging and abandonment plan must be updated throughout the life of the CCS project. Therefore, no changes were made to the Protocol in response to this comment.

M-13.4. *Well Plugging and Abandonment – Monitoring and Observation Wells*

Comment: Plume Stability – CARB considers plume stability to be achieved when injected or displaced fluids no longer have the potential to migrate above the storage complex (defined as the reservoir and two overlying confinement layers with an intervening, porous dissipation layer). Whereas this is a functional definition (note comment below on confining system requirements), CARB is proposing that monitoring wells be left open until plume stability is established. This is problematic from two standpoints: 1) wells left idle for extended periods of time in and of themselves comprise an integrity risk and 2) sensing (e.g., pressure) at the well locations may not reflect the actual status of the plume, particularly at distal extents of the Area of Review (AoR). Placing wells early in the injection phase at such distal locations would mean that wells may be idle for an extended period before receiving a useful signal. A more useful solution would be to give the operator the option of conducting imaging surveys and / or drilling new wells around the time of injection cessation based on the best understanding of plume status at the time. This would allow the operator to plug unnecessary wells and obviate the need for lower value, long-term monitoring (i.e., 100-year PISC). (CHEVRON1_112-16)

Agency Response: Staff agrees with the commenter's concerns with idle wells. In response to this comment, staff modified the Protocol language in subsection C.5.2.(b)(3) such that monitoring and observation wells are no longer required to remain open until plume stabilization, and may be plugged and abandoned following the risk assessment and post-injection site care and management plan.

M-13.5. *Well Plugging and Abandonment – Injection Termination*

Comment: Plugging and Abandonment of all wells within 24 months of CSS Injection Termination: This would not be practical in large scale EOR projects involving dozens or hundreds of wells. Additionally, producers will likely remain active for some time following CSS completion. (CRC1_35-2f)

Agency Response: In response to these comments, and those of other comments submitted in the 1st 15-day comment period (please see Response M-4.1 in Chapter V), staff modified subsection C.5.2.(b)(3)(A) of the Protocol to change the requirement such that all wells (with the exception of monitoring and

observation wells) must be plugged within 24 months after the project has entered the post-injection site care and monitoring period.

M-14. *Deed Notification Requirements*

Comment: We acknowledge the importance of ensuring that notice to a prospective property owner that there is a CO_2 storage complex below the surface is critical to maintaining the long term integrity of the CCS Project. Satisfying this provision will likely require a project operator to negotiate or acquire the surface in fee. In some cases, there may be several private surface owners for a given CCS Project, and possibly public land involved as well. 30-days is likely insufficient time to negotiate and complete the deed notations or, in the alternative, to acquire the surface in fee. We suggest a one-year period instead. However, during this one-year period, all other protocol requirements to monitor and report on the project will remain fully in-place to ensure the integrity of the storage complex.

We also suggest clarifying language to specify when the deed notice must be perfected. It appears clear from the information that Section C.5.2(f) requires in the notation recorded on the deed, that it is a post-closure requirement that cannot be demonstrated until injection ceases (e.g., the volume of fluid injected will not be known until after injection ceases). We suggest the following revision to Section C.5.2(f):

"Within ~~30 days~~ one year after completion of injection, each CCS Project Operator must record a notation on the deed to the CCS project property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information [….]" (CCSPD2_B15-1)

> **Agency Response:** Staff appreciates the commenters' support for adding notice for any property sales following the end of a CCS project. Staff acknowledges the commenters' concerns with the length of the time required to negotiate a surface fee, and thus, staff modified the Protocol language in subsection C.5.2.(f) to lengthen the time from 30 days to six months after injection completion. Staff believes that six months is sufficient time to conduct the proper deed notation.

M-15. Multiple Comments: *Concerns with Baseline Monitoring and Soil Flux*

Comment: Baseline soil flux monitoring is a cornerstone strategy of the Protocol, which could result in false positives or miss leakage altogether because of a proven lack of broad reliability, with results confounded by natural processes. Using a baseline strategy, a monitoring technology provides a "snapshot" of the current condition and can be compared to a similar snapshot at a future date. Using a baseline strategy, a false indicator of leakage will trigger further investigation which may require substantial investment. Moreover, methodologies and technologies will evolve and therefore monitoring strategies should take into account that it may be a challenge to compare the results of newer technologies with older technologies in the future.

In contrast, soil baselines have been demonstrated to be unreliable and may lead to greater uncertainty and wasted monitoring resources such as in the Kerr Farm incident (*see, e.g.,* Romanak et al. (2013) https://www.sciencedirect.com/science/article/pii/S1876610213005699). Soil fluxes may vary with season, from year to year, and will undoubtedly change as climate change affects soils and natural gaseous components such as methane and CO_2. Instead, a more effective approach is to require that operators propose and demonstrate the effectiveness of monitoring tools appropriate for the geologic and ecological environments within which the operate. Our recommendation relative to soil flux monitoring is to eliminate the word "baseline," and instead establish soil concentrations to be utilized in a *process-based* approach rather than establishing these measurements as a snapshot at a certain period of time.[4] Tasks to facilitate process-based monitoring may include: 1) base characterization: measure ratios of gases (N, CO_2, O_2, CH_4) in ambient atmosphere, soils, AZMI; 2) develop workplan and timeframe for collecting samples; 3) attribution strategy (*see* ARB presentation by K. Romanak). Strategies should also take into account soil gas trends related to climate change over the requisite monitoring period. (CATF1_100-5)

Comment: Baseline soil flux monitoring is a cornerstone strategy of the rule which could result in false positives or miss leakage altogether because of proven lack of broad reliability which can be confounded by natural processes. Using a baseline strategy, a monitoring technology provides a "snapshot" of the current condition and can be compared to a similar snapshot at a future date. Changes observed may be an indicator of leakage. However, soil baselines have been demonstrated to be unreliable and may lead to greater uncertainty and wasted monitoring resources.[7] Soil fluxes may vary with season, from year to year, and will undoubtedly change as climate change affects soils and natural gaseous components such as methane and carbon dioxide. Instead, a more effective approach is to require that operators propose and demonstrate the effectiveness of monitoring tools appropriate for the geologic and ecological environments within which they operate.

[7] See, for example. Romanak et al., (2013): https://www.sciencedirect.com/science/article/pii/S1876610213005699, as well as our Dec 4, 2017, stakeholder feedback to ARB on the Draft CCS Accounting and Permanence Protocol and on Draft Regulatory Amendments to the Low Carbon Fuel Standard.

Our recommendation relative to soil flux monitoring is to eliminate the word "baseline", and instead establish soil concentrations to be utilized in a process-based approach rather than setting them as a snapshot of a certain period of time. Tasks may include:

- Base characterization: measure ratios of gases (N, CO_2, O_2, CH_4) in ambient atmosphere, soils, and the "Above-Zone monitoring Interval".
- Develop work plan and timeframe for collecting samples.
- Well attribution strategy.[8] Strategies should take into account soil gas trends related to climate change over the requisite monitoring period.

[8] See: presentation to CARB by K. Romanak, 2016.

(CCSPD1_106-12)

Comment: Monitoring methodology during the PISC – The type of monitoring specified for the bulk of the 100-year period, soil and atmospheric gas analyses, is increasingly recognized by research in the field as prone to near-surface complexities and subject to misinterpretation of "attribution".[3] Although such monitoring is not particularly expensive, a risk-based monitoring program conducted over a shorter PISC period would give CARB a much better understanding of the system's future containment performance.

[3] https://www.sciencedirect.com/science/article/pii/S1750583615001929

(CHEVRON1_112-15)

Comment: The final protocol should not dictate the specific monitoring approach and methods used to address surface, near-surface, and deep subsurface for CO_2 leakage that may endanger public health or the environment. Research has shown that collecting baseline and background data for comparison with future collected data may not be the most effective approach. What is most important is to have an effective strategy and approach for determining whether observed CO_2 is attributable to the CO_2 sequestration operation. There are a number of ways this can be done effectively, and some of those would avoid the expense and intrusiveness of elaborate monitoring arrays such as those that have failed to collect meaningful data from numerous pilot and demonstration projects to date.

"The CCS Project Operator must submit ~~a Baseline Testing Plan~~ with the application for Sequestration Site Certification a monitoring strategy and plan to address surface, near-surface, and deep subsurface for CO_2 leakage that may endanger public health or the environment." (RFVV1_126-10)

Comment: This should not be the only acceptable approach, as noted in the comment immediately above [RFVV1_126-10].

"Baseline data on CO_2 concentrations and fluxes collected prior to operation ~~must~~ may be used for history matching and comparison to levels during and after the operational phase of the CCS project to detect any CO_2 leakage to the deep subsurface, shallow subsurface, and surface or atmosphere." (RFVV1_126-11)

Comment: The final protocol should not dictate the specific monitoring approach and methods used to address surface, near-surface, and deep subsurface for CO_2 leakage that may endanger public health or the environment. Research has shown that collecting baseline and background data for comparison with future collected data may not be the most effective approach. What is most important is to have an effective strategy and approach for determining whether observed CO_2 is attributable to the CO_2 sequestration operation. There are a number of ways this can be done effectively, and some of those would avoid the expense and intrusiveness of elaborate monitoring arrays such as those that have failed to collect meaningful data from numerous pilot and demonstration projects to date.

"The CCS Project Operator must submit a descriptive report of ~~baseline~~ monitoring strategy, data collection, and corresponding interpretations with the application for CCS

Project Certification. ~~The report must include surface air or soil gas analyses, and CCS Project Operators must submit, at a minimum, the following:~~

~~(A) Site characteristics (e.g. soil type, soil organic carbon content, vegetation type and density, topography, surface water hydrology);~~

~~(B) Sampling locations (in map form) and dates sampled;~~

~~(C) Atmospheric conditions;~~

~~(D) Sampling and analytical methods, including detection limits;~~

~~(E) Results presented as concentrations and fluxes in tabular and graphic form, including quality assurance (QA) samples and analyses;~~

~~(F) Methods and results of regression analyses; and~~

~~(G) Methods and results of any ecological modeling or sensitivity analysis performed, including input data and outputs.~~

~~(h) The CCS Project Operator must demonstrate that the locations sampled represent a reasonable grid size and that potential point sources are represented and will serve as a good baseline to compare to future monitoring data. The CCS Project Operator must also demonstrate that seasonal and diurnal variations in CO_2 levels have been captured and describe the variability in the data for future reference. If an inadequate time series of analyses was performed or if there are concerns regarding the quality of analytical data, the CCS Project Operator may need to collect and submit additional data.~~" (RFVV1_126-13)

Comment: The final protocol should not dictate the specific monitoring approach and methods used to address surface, near-surface, and deep subsurface for CO_2 leakage that may endanger public health or the environment. Research has shown that collecting baseline and background data for comparison with future collected data may not be the most effective approach. What is most important is to have an effective strategy and approach for determining whether observed CO_2 is attributable to the CO_2 sequestration operation. There are a number of ways this can be done effectively, and some of those would avoid the expense and intrusiveness of elaborate monitoring arrays such as those that have failed to collect meaningful data from numerous pilot and demonstration projects to date.

"The CCS Project Operator must ~~perform continuous and intermittent geochemical monitoring of the soil and vadose zone, including sampling of CO2, natural chemical tracers, and introduced tracers, in order to~~ implement a strategy to detect potential releases from wellbores, faults, and other migration pathways, and ~~must~~ should consider the following methods:" (RFVV1_126-16)

Comment: See comment above [RFVV1_126-16]; the strategy adopted may take alternative forms that would prove more effective, less costly and less environmentally intrusive.

"A monitoring strategy must be specified and should ~~include soil gas and surface air monitoring around the wellbore, and should~~ focus on identifying CO_2 flux around the wellbore that may indicate a catastrophic leak." (RFVV1_126-16a)

> **Agency Response:** Staff acknowledges the commenters' concerns with the baseline monitoring and testing plan requirements, and the limitations and potential for errors of proposed soil gas and atmospheric monitoring methods. In developing the Protocol, staff worked to forge requirements with baseline monitoring methods that would be cost effective and simple to maintain over long periods of time.
>
> In response to these comments, staff revised subsection C.2.5 of the Protocol to replace prescriptive requirements with a strategy for baseline testing and monitoring that is more flexible and performance-based. The new requirements are such that the baseline monitoring and testing must support and inform the detection of CO_2 leakage. The change in requirements allows for the inclusion of site-specific monitoring technologies, and places more emphasis on monitoring strategies able to detect, validate, quantify, and enable mitigation.
>
> Staff also added details on baseline testing and monitoring data collection and analysis, including specifying the types of data that must be collected, the adequacy of the data collection and analysis, and listed the potential, but not mandated, tools that the operators may use for baseline testing. The new requirements include criteria for a monitoring strategy such that monitoring is (1) sufficient to track the CO_2 plume and (2) appropriate for history matching. Staff worked to explicitly link the risk assessment to the testing and monitoring plan, and emphasize the evaluation of potentially impacted properties.
>
> Finally, staff replaced certain required data (e.g., soil type, soil carbon content, surface water hydrology, etc.) with new data requirements (downhole pressure, fluid chemistry, etc.), to improve the information used to detect potential CO_2 leakage.

M-16. Multiple Comments: ***Injection Pressure***

Comment: Extensive consideration of geomechanical risk is underway. Suggest that this rate be tied to current best practices in risk management, which should be site dependent.

"…ensure that injection pressure does not ~~exceed 80 percent of the fracture/parting pressure of the sequestration zone so as to ensure that injection does not~~ initiate or propagate existing fractures…" (GCCC1_14-120)

Comment: Injection Pressure: Limiting pressure to 80% of sequestration zone parting pressure, per Step Rate Test inflection, is overly restrictive and could hinder EOR processing rates to the point of rendering EOR/CCS projects uneconomic. There are two primary technical reasons to revise this requirement:

1. Breakdown pressure of the upper confining layer or geologic seal is the limit that should be established and must not exceeded. Minor near-wellbore displacement of the reservoir sands, as established via step rate tests, is very common in moderate permeability sands under fluid injection, and it has no effect on cap rock integrity and poses no risk to zonal sequestration.
2. Establishing a limit of 80% seems arbitrary and overly restrictive. This is also inconsistent with state UIC regulations. (CRC1_35-2a)

Comment: The use of an 80 percent limit is arbitrary and will serve to unnecessarily limit projects that could be extremely effective in mitigating GHG emissions. All that is necessary is a limit that precludes injection pressures that could create fracture pathways through the confining layers. USEPA uses 90 percent, but even that is arbitrary. If a limit is imposed, there should also be an alternative for demonstrating that a project can rely on alternative means for ensuring that injection does not initiate or propagate existing fractures that would create pathways out of the sequestration zone.

"The CCS Project Operator must ensure that injection pressure does not exceed 80 percent of the fracture/parting pressure of the sequestration zone so as to ensure that injection does not initiate or propagate existing fractures in the sequestration zone. In no case may injection pressure initiate fractures in the confining layer, or cause movement of the injection or formation fluids out of authorized zones." (RFVV1_126-15)

Agency Response: During the development of several provisions of the Protocol, including the maximum allowable injection pressure, staff consulted with staff at other regulatory agencies, including California's Department of Oil, Gas, and Geothermal Resources (DOGGR). Staff chose an injection pressure limit of less than or equal to 80 percent of the formation/parting pressure of the sequestration zone in order to prevent fracturing of the caprock after discussions with DOGGR.

In response to these comments, and those of the 1st 15-day comment period (please see Response M-9.5 in Chapter V), staff modified subsection C.3.3.(b) of the Protocol to add a provision that allows for alternative injection pressures above 80 percent fracture pressure, provided the operator submits a demonstration explaining why the alternative pressure must be used.

M-17. Multiple Comments: *Operational Monitoring Requirements*

M-17.1. *Annular Pressure*

Comment: Annular Pressure Requirement: Maintaining the annulus immediately above the packer at 100-200 psi above the tubing bottom hole pressure is unnecessary to maintain confinement of the injectate and increases the risk of environmental and safety incidents without providing any benefit. Injection packers are designed to operate under differential pressures, thus reducing persistent stress on the wellbore casing and wellhead, both of which combine to provide the final containment barrier. In the event of a packer leak, the required surface casing pressure monitoring equipment would immediately indicate leakage and the need for corrective intervention.

Holding high back-pressure on the casing is a risk to casing integrity and to safety. In EOR operations, the casing is designed to accommodate pressure changes from dynamic injection behavior, such as thermal expansion during water alternating gas operations, and there is no need to artificially increase the back-pressure. (CRC1_35-2b)

> **Agency Response:** Staff acknowledges the commenters' concerns about the high pressure requirement within the annulus. For this provision, staff followed the U.S. EPA's Class VI rule, which requires that the pressure in the annulus be greater than the injection pressure (40 CFR 146.89(b)). However, staff understands that there are cases in which keeping the annulus pressure 100 to 200 psi higher than injection pressure may increase the risk of mechanical integrity failure. In response to these comments, staff kept the requirement for maintaining a higher annular pressure than the injection pressure, and removed references to specific numerical pressure values. This modification keeps the Protocol in line with the Class VI rule, as the rule allows for the use of alternative annulus pressures.

M-17.2. *Tracking Dissolved CO_2*

Comment: The CCS Protocol Specific Purpose and Rationale references "[t]esting and monitoring to track the extent of the dissolved and free-phase CO_2 plume and pressure front."[9] However, we are unable to find such requirements in the proposed Protocol. CARB should clarify its intent and/or rationale.

[9] ATTACHMENT 2: CCS Protocol Specific Purpose and Rationale, Page 169/175.

CO_2 saturated water sinks while free phase CO_2 is buoyant. This is one of the primary mechanisms of trapping CO_2 in the subsurface, and is termed "dissolution trapping". Monitoring dissolved CO_2 is not straightforward, and could introduce additional risks by requiring the drilling of many wells to collect water samples. Given that every well impacts the environment and represents a new leakage pathway, a program that necessitates well-drilling may not generate a net environmental benefit. In addition, no geophysical methods are currently available to detect dissolved CO_2 except in low salinity situations. We recommend that an operator only be required to monitor

dissolved CO_2 when the risk assessment shows that there could be some endangerment to a receptor. (CCSPD1_106-13)

> **Agency Response:** The requirement to monitor dissolved CO_2, as referenced in the Purpose and Rationale, is a residual provision from a previous informal draft version of the Permanence Protocol. This requirement was removed from the CCS Protocol prior to its publication on March 6, 2018, and was inadvertently included in the Purpose and Rationale.

M-17.3. Injection Fluid Composition

Comment: Section 1.1.3.4(b) states that an analysis of any changes to the composition of the injection fluid must be submitted to the EO for review and written approval at least 30 days prior to injection. CARB should clarify what constitutes "changes to the composition" as CO_2 percentages may vary in the course of operations. Additionally, WAG injection via CO_2-EOR may have water alternating with CO_2. CARB should clarify whether the water injection cycle is included in the definition of Injection Fluid, which is not defined. (CCSPD1_106-35)

> **Agency Response:** Staff acknowledges the commenter's concerns with reporting injection fluid compositions. Staff included this provision in an effort to prevent CCS projects from significantly altering their fluid compositions mid-project. If a project was certified for different compositions of injection fluid, such as water-alternating-gas (WAG) injection via CO_2-EOR, the operator would not be required to report the analysis of the approved injection fluids to CARB. However, if the composition of the CO_2 meant for injection changed significantly, such that the CO_2 would no longer meet the approved compositional range, the operator would be required to submit an analysis of the new composition.

M-17.4. *Operational Monitoring During the Active Life of the CCS Project*

Comment: Monitoring, in general, should be designed to detect leakage in a wide range of geologic project environments, some of which could be outside of the State of California. Monitoring plans should describe the detection process, and the effective threshold at which leakage from any possible pathway from reservoir to surface will be detected. This would include a detailed explanation (using maps and modeling) of what steps of measurement and modeling will be used to trigger a finding of leakage detection. The plan should explain in detail the process by which leakage will be verified, quantified, and mitigated, and if mitigated how the mitigation will be validated, including the accuracy and precision of the methods utilized.

Regarding the regulatory structure, we think that the Protocol would benefit from more clearly defined boundaries between the project phases. In particular, section C.4.1 should be explicitly limited to the injection phase of the project. This could be accomplished by adding the final sentence to read:

> "Testing and monitoring associated with CCS projects during the active life of the CCS project must include:[...]"

This would clearly limit the prescriptive monitoring requirements to the injection phase of the project. To the extent that monitoring is required post-injection, this is best addressed in C.5.2, Post-Injection Site Care and Site Closure. (CCSPD1_106-11)

> **Agency Response:** Staff agrees with the commenter, that more clearly defined boundaries provide clarity to the Protocol. In response to this comment, the phrase "during the active life of the CCS project," was added to the provisions of subsection C.4.1(a).

M-17.5. *Downhole Seismic*

Comment: Downhole seismic monitoring: The requirement for permanent downhole seismic monitoring at every injector is cost prohibitive. EOR/CSS projects will include dozens or hundreds of injectors, and there is no need for such monitoring given the growing array of sensitive surface seismic networks. (CRC1_35-2d)

> **Agency Response:** Staff understands and agrees with the commenter's concerns about the practicality and/or necessity of deploying downhole seismic monitoring equipment at each well. Staff modified subsection C.4.3.2.3(a) of the Protocol to clarify that operators must deploy and maintain a seismic monitoring *system* in order to determine the presence or absence of induced micro-seismicity associated with the project wells. The design of the system would be subject to review and approval.

M-17.6. *Monitoring of CO_2 Plume and 3-D Seismic Surveying*

Comment: Monitoring the CO_2 plume: This process could become cost-prohibitive. One example would be the stated goal to track the "pressure front" associated with an injectate plume. Repeated post-shut-in 3D seismic surveying would also be very costly and not provide any corresponding benefit, particularly since it is ineffective under certain geologic conditions. (CRC1_35-2e)

> **Agency Response:** Please see Response M-2.1 in this chapter for staff's response to the comment related to the term "pressure front."
>
> The proposed CCS Protocol does not prescribe specific technologies for monitoring the CO_2 plume, and CCS project operators have the flexibility to choose from the best available methods for their project. Please see Response M-3.1 in this chapter for staff's response to the commenter's concern with costs related to the Protocol provisions.

M-18. Multiple Comments: *Reporting Requirements*

M-18.1. Multiple Comments: *Quarterly Pressure Elevation*

Comment: This ["report elevated pressure measurements quarterly"] is very high frequency, as data are usually not meaningful until compared to a model. (GCCC1_14-144)

Comment: "*Conduct ~~quarterly~~ bottom-hole pressure tests in the monitoring wells in order to track the position of the pressure front;*" (CCSPD1_106-48)

> **Agency Response:** In response to these comments, staff modified the Protocol to add a stipulation that the frequency of measurement may be adjusted based on the previously measured rate of change (of pressure), provided the operator provides a justification for the alternative monitoring strategy.

M-18.2. *Triggering Events*

Comment: In Section C.1.1.3.5(a)(3), it is required that "any" triggering event to be reported with no stated threshold. WSPA requests that ARB consider a threshold for triggering events. (WSPA3_93-10)

> **Agency Response:** Staff acknowledges the concerns of the commenter that a lack reporting thresholds could lead to issues with the over-reporting of triggering events, however, within subsection C.1.1.3.5(a)(3) referenced by the comment, there is a provision to follow the requirements of subsection C.3.4 Operating Restrictions and Incident Response. This subsection lists the conditions under which an operator must report an incident. Therefore, staff did not modify the protocol in response to this comment.

M-18.3. *Seismic Evaluation Following an Earthquake*

Comment: Section C.3.2.3(e) provides: "The results of the seismic evaluation must be reported to the Executive Officer within 30 days following the earthquake". <u>In cases where access to the site following such a seismic event is limited, we recommend that CARB allow for preliminary results to be supplied within 30 days, and final results within 120 days.</u> Even under normal circumstances, 30 days may not be sufficient time to complete the analysis. Processing and interpretation of seismic data is a time consuming activity requiring many hours of time on large computing clusters and multiple iterations. (CCSPD1_106-24)

> **Agency Response:** In response to this comment, staff modified the Protocol such that preliminary results are due within 30 days, and a final report is due in 120 days.

M-18.4. *Additional Required Information*

Comment: In Section C.1.1.3.3(a)(1)(I), the requirement to provide "Any other information required by the Executive Officer" is overly broad. This requirement should for "Any relevant other information required by the Executive Officer". (WSPA3_93-9)

> **Agency Response:** Staff does not agree that requiring "relevant" information is different than "any" information, and therefore, no changes were made to the Protocol.

M-19. Multiple Comments: *Operating Restrictions*

M-19.1. *Conditions for Cessation of Injection*

Comment: In Section 3.4(a)(8), the shut-down requirement for "any certification condition or to local regulatory requirements" is overly broad. This requirement should be for "any relevant certification condition or to local regulatory requirements". (WSPA3_93-12)

> **Agency Response:** Please see staff's response to comment WSPA3_93-12 in Response M-18.4 in this chapter.

M-19.2. *Conditions for Resuming Injection*

Comment: In Section C.3.4, there are several requirements for when injection must cease but no defined process when injection can resume. Related to this comment, it is not clear what amount of leakage would require shutting in a well and what standard needs to be met to bring a well back into service. WSPA requests that CCSP provided clarity on these situations. (WSPA3_93-11)

> **Agency Response:** In subsection C.3.4, staff lists 8 separate incidents that can result in the need to cease injection. These incident types that lead to ceasing injection are based on leakage occurring or a potential risk of leakage occurring. Resuming injection would be approved after the potential risk has been remedied, and the operator can show that continued injection would meet the requirements of the permanence certification. Staff does not agree that modification of the language is necessary.

M-19.3 *Scope of Requirement for Cessation of Injection*

Comment: Section C.3.3(f)(1) states that all credits generated are subject to invalidation if injection does not cease immediately if a well shows indications of mechanical integrity issues. CARB should clarify whether this applies to ceasing injection at that well or across the entire CCS Project. <u>Given the scale of potential CCS Project operations, we suggest it apply to ceasing injection at the well. This would also be consistent with Section C.3.4(a). Secondly, CARB should clarify what the period of credit invalidation is.</u> (CCSPD1_106-37)

> **Agency Response:** In response to this comment, staff modified the language of the Protocol to clarify that this provision applies to the affected well or wells, and any other wells that may exacerbate the leakage risk.

M-19.4. *Restrictions on Drilling During Operation*

Comment: The current language is overly broad because it appears to prohibit the drilling of wells that are part of the CCS project and any associated EOR operation. Even this language seems overly restrictive because it would preclude future CCS projects in deeper formations even though techniques are readily available to ensure

that any wells drilled through an existing CCS project would include application of controls to prevent any release of sequestered CO_2.

"The CCS Project Operator must show proof that there is binding agreement among relevant parties that drilling injection or extraction wells that are not part of the CCS project and that penetrate the confining layer above the sequestration zone are prohibited within the AOR to ensure public safety and the permanence of stored CO_2." (RFVV1_126-20)

> **Agency Response:** Staff does not agree with the commenter's assertion that the language is overly restrictive for EOR operation. Any drilling of new wells, either concurrent with the project or in the future following the cessation of injection, must be part of the application for Permanence Certification. If an EOR operator wants to modify the drilling plans from the original application, they have the ability to do so, provided the Executive Officer approves the new plans. This provision is applicable to third parties who wish to drill through the CCS project boundaries into lower formations for the purpose of resource extraction unrelated to the CCS project.

M-20. ***Well Integrity Classifications and Testing***

Comment: The protocol currently defines well integrity as a binary system under which legacy wells need or do not need corrective action. We recommend a three class system to account for more timely interventions. The recommended assessment system would include determination of:

- Wells assessed to be effectively sealed (by plugs or natural closure)
- Wells that require intervention, and
- Wells that will be monitored to ensure that they maintain integrity; if not, they will be replugged. This assessment would account for the current extent of the pressure and CO_2 plume and imply a rolling program of well work as the usage of the store expands.

The inclusion of the third class allows the operator to avoid reopening wells that have been sealed by natural mechanisms such as shale creep, thereby minimizing environmental impact of well operations and reducing the risk of leakage through the reopening of wells. The requirement for monitoring maintains the security of the store.

Section C.4.2(b)(2) states that wells must be tested for mechanical integrity at least once each year, or on a testing schedule approved by the Executive Officer. We suggest the option of aligning the testing schedule with regulatory bodies overseeing mechanical integrity testing in other jurisdictions to prevent redundancy and overlapping authority, provided this does not result in a dilution of confidence in mechanical integrity and storage security. (CCSPD1_106-22)

Agency Response: Staff thanks the commenter for their suggestion on well integrity classifications. The CCS Protocol was designed to err on the side of caution, as such any well that may be deemed to require monitoring for mechanical integrity would instead be required to be replugged prior to injection initiation. As projects come online under the Protocol, and various technologies develop to identify wells that are effectively sealed, this requirement may be reevaluated as appropriate.

M-21. Multiple Comments: *Staging of Well Remediation*

Comment: We suggest that CARB have the option to approve staging of well remediation in cases where well records are proven to be of good quality, all required efforts have been made to locate unknown or orphan wells, and there is a high degree of confidence in the knowledge of the location and state of wells that could act as CO_2 leakage pathways. In early stages of projects only some wells will be impacted by injection. Allowing delay of preparation of wells in outlying areas is a normal practice and low risk, and allows funding and effort to focus on high risk areas proximal to the active injection wells. Well remediation staging plans should be developed in collaboration with CARB and consistent with the area of review modeling results. (CCSPD1_106-6)

Comment: The final protocol should allow a phased approach to corrective action as USEPA has done in its Class VI rule (40 CFR 146.84(b)(2)(iv)). As USEPA noted in the preamble to the final rule: "Due to the anticipated large size of the AoR for Class VI wells, EPA proposed allowing owners or operators to conduct corrective action on a phased basis during the lifetime of the project, at the discretion of the Director. In these cases, corrective action would not need to be conducted throughout the entire AoR prior to injection. Corrective action would only be necessary in areas near the injection well with a high certainty of CO_2 exposure during the first years of injection as informed by site characterization data and model predictions. Artificial penetrations in areas farther from the injection well would be addressed after injection has commenced, but prior to CO_2 plume and pressure front movement into that area." USEPA retained the option of phased corrective action in the final rule, and that approach should be used in the final protocol as well for the same reasons.

"Prior to CCS Project Certification, CCS Project Operators must implement the corrective action plan and perform corrective action on all wells within the delineated AOR that require corrective action prior to CO_2 plume and pressure front movement into the area where the wells are located." (RFVV1_126-9)

Agency Response: Staff acknowledges the commenters' concerns regarding well remediation. However, staff does not agree that remediation should be staged at this time. The CCS Protocol was designed to err on the side of caution, as such in order to most fully reduce risk related to legacy wells the CCS Protocol requires the remediation of wells (that have the potential to be vectors for CO_2 leakage) prior to injection initiation. There needs to be upfront certainty that all wells will be plugged or remediated prior to intersection with the CO_2

plume, regardless of the solvency of the company or rate of plume movement. As projects come online under the Protocol, and technologies that evaluate a well's risk of leakage are improved to provide more granularity on timeframe of needed remediation, this requirement may be reevaluated as appropriate.

M-22. *Permanence Certification*

M-22.1. *Permanence Certification Transfer*

Comment: "The Permanence Certification is ~~non-~~transferable subject to approval by the Executive Officer that must be noted in a revised Permanence Certification." (CATF1_100-11, CCSPD1_106-41)

Comment: Section C.1.2(b) provides:

"The Permanence Certification is non-transferable."

We are not clear on the rationale behind this provision. We can envision a situation where it both be preferable from an environmental standpoint to transfer a project to a more competent and/or financially sound operator, and commercial situations where an operator may wish to transfer a project to a new owner. CARB should explain the rationale behind this provision. If transfers are to be allowed, subsequent CCS Project Operators should demonstrate that they meet the requirements of the Protocol. (CCSPD1_106-29)

> **Agency Response:** Please see staff's response to comment CATF1_100-7b in Response M-3.2 of this chapter concerning the transfer of Permanence Certification.

M-22.2. *Permanence Certification Expiry*

Comment: Section C.1.2(c) provides:

"Permanence Certification must expire, and be deemed null and void, upon the first day following 24 consecutive months of no injection at the GSC project, and a new approval process and re-certification would be required prior to restarting injection."

This is an unnecessary restriction on a CCS Project's operational parameters. There is significant uncertainty as to the consistency that the LCFS market might have in the early years of development. Having made the investment to obtain a Permanence Certification, a project operator may find that the infrastructure to insure reliable supplies of CO_2 for a project is not yet fully operational or may be subject to periodic disruptions. It is possible that some disruptions may require a significant investment and time to cure (e.g., a pipeline may need to be constructed that will require obtaining multiple right of ways that could require significant time to obtain).

We recommend that an operator be allowed to suspend injection following a submittal to, and subsequent approval by CARB. Once reliable supplies of CO_2 were restored,

and assuming the operator has maintained all other aspects of the CCS Project in accordance with the application, injection should be permitted to resume.

We offer the following proposed alternative language:

> "1.2(c) Prior to entering post closure, in the event injection is suspended at the CCS Project, an operator may apply for a temporary suspension of its Permanence Certification. The operator shall continue to comply with the monitoring, reporting and verification requirements of this protocol and its application at all times during the suspension. Before restarting injection, the operator shall provide the Executive Officer with ten days advance notice." (CCSPD1_106-30)

> **Agency Response:** At this time, staff does not see the need to change this provision in the Protocol. While staff can envision a scenario like the one presented by the commenter, this situation is unlikely to occur within the initial implementation period of the Protocol. As projects come online under the Protocol, and if similar issues occur, this requirement may be reevaluated as appropriate.

M-23. ***Binding Agreements***

Comment: Section C.9(c) requires the CCS Project Operator to show proof that there is a binding agreement among relevant parties that drilling or extraction that penetrate the confining layer above the sequestration zone are prohibited within the AOR to ensure public safety and permanence of stored CO_2. It is critical that there be controls in place to safeguard against a party penetrating the confining layer or sequestration zone in such a manner that there is a risk that stored CO_2 is released. However, a contractual agreement is only one tool to safeguard against such an event. In some states there are existing regulatory requirements (e.g., in Texas, rules by the Department of Licensing and Regulation), that prescribe how wells are to be advanced to avoid uncontrolled releases from the subsurface or mixing of fluids from different zones. In some cases, these regulatory requirements may be superior to a contractual agreement because of the involvement of the state regulatory authority. The Protocol should give the Executive Officer the option to accept such requirements if an operator demonstrates that existing regulatory obligations provide at least the same level of protection as may be afforded by a contractual agreement. We suggest the following revision to Section C.9(c):

> "The CCS Project Operator must show proof that there is a regulatory obligation or a binding agreement among relevant parties that drilling or extraction that penetrate the confining layer above the sequestration zone are prohibited within the AOR to ensure public safety and the permanence of stored CO_2". (CCSPD1_106-38)

> **Agency Response:** Staff acknowledges the commenter's concerns with contractual agreements and regulatory authority. At this time, staff does not see the need to adjust this provision as staff continues to believe contractual agreements are the most appropriate tool to implement this provision. As the

implementation of the Protocol commences, and if this issue should arise, the requirements may be re-evaluated.

M-24. Multiple Comments: *Eligible Entities*

Comment: The rule is too restrictive because it appears to preclude credit for CCS conducted in compliance with the CCS protocol at an EOR operation that uses CO_2 captured by a power plant or industrial facility that is not located at the CO_2-EOR project. The Order should allow credit for CCS projects where the CO_2 is captured at any power plant or industrial facility, transported to an EOR project and injected in accordance with the CCS protocol.

"Alternative fuel producers, refineries, and oil and gas producers that capture CO_2 on-site and geologically sequester CO_2 either on-site or offsite or that produce fuels using oil or gas for CO_2-EOR operations that use captured CO_2." (RFVV1_126-21)

Comment: Th[ese] provision[s] [95490(c)(1), 95490(c)(2)(B), and 95490(g)] confirm the clear intent to allow credit where CO_2 is captured at one site and then transported to another site for injection as part of either a geological sequestration project or as part of a CO_2-EOR project.

"An application must be filed jointly by an entity that captures CO2 and an entity that sequesters the resultant CO2, unless the same entity is responsible for CO2 capture and sequestration."

"An engineering drawing(s) or process flow diagram(s) that illustrates the project and clearly identifies the system boundaries, relevant process equipment, mass flows, including the quantity of CO_2 injected into pipeline or delivered by other modes of transport for CO_2 injection, and energy flows necessary to calculate the CCS credit;"

"*Recordkeeping*. Pursuant to section 95491.1 and the CCS Protocol, each applicant that receives approval as a CCS credit generator must maintain records for the CCS project, including records necessary to verify permanent sequestration. At a minimum, the following records must be kept:

(1) The quarterly volume of alternative fuel, petroleum fuel, crude oil/natural gas produced and delivered to California;

(2) Energy use and chemical use data for the carbon capture facility and CO_2 injection facility;" (RFVV1_126-22)

Agency Response: As noted by the commenter, Sections 95490(c)(1), 95490(c)(2)(B), and 95490(g) of title 17, CCR demonstrate staff's intent to include CO_2-EOR operations that use captured CO_2 generated off-site by eligible entities as entities that are eligible to submit project applications and, if approved, receive CCS credits, under Section 95490(a) of title 17, CCR. However, staff did not and does not intend to include power plants or industrial facilities that use

captured CO_2 for CO_2-EOR as eligible parties. Therefore, staff did not modify the Protocol in response to these comments.

N. Reporting and Recordkeeping

N-1. *Support for the Proposed Amendments to the Reporting and Recordkeeping Provisions*

N-2. *Reporting*

N-2.1. *LCFS Reporting Deadlines*

Comment: CARB has set quarterly reporting deadlines to be the end of each following quarter.

1. CARB should shift the third quarter reporting deadline to January 15.

The December 31st reporting deadline is unique in that it is the only quarter end coinciding with significant holidays and associated vacation disruptions. (FHR1_18-5)

Agency Response: Staff appreciates the commenter's suggestion to modify quarterly reporting timelines to avoid coincidence with holidays. Under California law, any action due to be completed upon a holiday may be performed upon the next business day with the same effect as if it had been performed upon the day appointed. Staff believes the reporting timelines and this flexibility are well understood and accepted in the industry and several stakeholders have designed their reporting systems around the current reporting schedules. Therefore, staff did not propose changes to the quarterly reporting timelines.

N-2.2. *Other Reporting Requirements*

N-2.2a. **Comment:** In § 95491(h), WSPA requests that the word "quarterly" be replaced with the word "annual", as LCFS quarterly reports are "progress" reports and the compliance must be demonstrated over an annual period. (WSPA2_61-23)

Agency Response: Staff proposed to change the terminology from "quarterly progress report" to "quarterly fuel transactions report" as each quarterly report consists of the fuel transactions data reported – credits and deficits are generated based on data reported in these quarterly fuel transactions reports. The annual compliance report is comprised of aggregated data from quarterly fuel transactions report and the annual summary of credit transactions data. Upon discovery of an error in previously submitted fuel transactions data, request to correct the affected quarterly fuel transactions report must be made. Therefore, staff did not propose to change "quarterly" to "annual" in 95491(h).

Comment: In Table 4, "Energy Densities and Conversion Factors for LCFS Fuels and Blendstocks," the unit for the energy density of CNG is currently represented as MJ/Therm, both of which are energy units. Table 4 provides the default value for the amount of energy in a unit mass or unit volume for all other fuels, and it may be clearer if CNG followed the same logic. (ECOENGINEERS1_B5-11)

Agency Response: Staff appreciates the commenter's insight but would like to highlight that staff proposed to change the CNG reporting units from standard cubic feet (scf) to Therms. To ensure the CNG units are consistent, staff also proposed to remove the energy density values for Pure Methane and Natural Gas in cubic feet per megajoule (MJ) and proposed to include a conversion factor for CNG in therms per MJ in the Table 4. To reflect this change, staff proposed to update the title of the Table 4 to *"Energy Densities and Conversion Factors for LCFS Fuels and Blendstocks."*

N-3. *Recordkeeping*

N-3.1. Multiple Comments: *Record Retention for Reporting Parties*

Comment: ARB is proposing to increase the record retention requirement from 5 years to 10 years. In the ISOR, ARB discussion of the rationale for this change talks about the sampling plans developed by the verification bodies and the need for these to be updated and learnings used to provide improvements in the verification process. There does not appear to be any compelling reason to extend this increase in record retention period to regulated entities and we ask that ARB remove this proposed change as it pertains to regulated entities. (P661_55-5)

Comment: In § 95491.1(a), WSPA requests that the ARB retain the retention period of 5 years, instead of the proposed 10 years. (WSPA2_61-24)

Comment: In Section 95491.1, staff proposes to increase the record retention period from five to ten years but fails to provide adequate rationale to support such a large increase burden on reporting parties. Rather, the inclusion of required, more regular third-party verification should reduce the risks associated with incorrect reporting and record-keeping. The record retention period should not be increased. (NESTE1_76-10)

Comment: CARB is proposing to increase record retention requirements from five years to ten years. This change contrasts with other regulatory programs and has no apparent purpose. We fear that it would be a burdensome new requirement to the regulated community with no clear benefit. CARB should retain the current five-year term. (CHEVRON1_112-32)

Comment: Regarding record retention, REG recommends a bifurcation on the requirements like MRR (95105) where some parties have a five year requirement and some have a ten year requirement versus a blanket ten year requirement for all parties. We recommend five years for all parties except those parties that have been subject to a CARB enforcement action (not just LCFS) or an adverse verification statement. We are not aware of any program where record retention beyond five or even seven years has been needed. (REG1_88-26)

Agency Response: Staff proposed records required to be maintained under the LCFS regulation shall be retained for ten years instead of five years to be consistent with other CARB market based programs, including Mandatory

Greenhouse Gas Reporting Regulation and Cap-and-Trade Program. Further, record retention for ten years will support any necessary CARB investigations and third-party verification in the event data previously reported must be corrected and the initial verification set aside.

N-4. Multiple Comments: *Proposed Obligation Transfer Period for Liquid Fuels*

Comment: § 95483 (a)(3) states that: *"For all liquid fuels, the period in which credit or deficit generator status can be transferred to another entity, for a given amount of fuel, is limited to two calendar quarters."* WSPA requests that ARB verify that the term "calendar quarters" does not mean a specific calendar year but rather the calendar quarter which the title is received and subsequent calendar quarter, regardless of overlap into a new calendar year (i.e., a title received in the fourth quarter of one year can change status through the first quarter of the next year). (WSPA2_61-8)

Comment: The proposed changes instituting a following-quarter time limit on obligated fuel transfers is demonstratively problematic. This can be challenge for renewable natural gas (RNG) and other credit generating fuels. The problem sought to be fixed seems to be a minority of entities that potentially could game the system by delaying obligation transfer over a change in compliance curve. This is very small percentage of activities in the tracking system, yet this proposed change will impact far more entities negatively.

The administrative burden associated with having to two separate transactions (credits and fuel) after only potentially holding a fuel three months seems excessive. There are also many IT systems in place that will need to be updated to address this new requirement. This all just seems very unnecessary. We are confident that the market will come up with workarounds, but that will just make the program more complicated. Therefore, we request that the short limit on obligation transfers be extended or removed. (LOVE1_73-4)

Comment: We have concerns with the practicality of 95483(a)(3) Transfer Period. We understand concerns that fuel may transfer with obligation after a CI benchmark has changed, but the potential solution seems to create more problems than solve. (REG1_88-9a)

Agency Response: Staff proposed the obligation transfer period to minimize instances where a fuel quantity reported in one compliance year is reported again in the following compliance year, resulting in different number of credits or deficits for the same amount of fuel in each year. Staff recognized that the two-quarter limit could be too limiting in some instances and, therefore, as part of the 15-day changes, proposed to increase the Obligation Transfer Period from two quarter to three quarters.

In response to WSPA2_61-8, staff agrees with the stakeholder's understanding and would like to clarify that subsequent quarters following the quarter in which

title was transferred would be considered for assessing compliance with this requirement, irrespective of the calendar year.

N-5. *Proposed Change of Ownership or Operational Control Provisions*

N-5.1. Comment: Section 95483.3 requires the current owner/operator to assume the compliance liability for the previous owner/operator and submit a single report covering the entire compliance period. The current operator must certify compliance for a portion of the compliance period where they did not have access to, influence over, or knowledge concerning compliance activities as they were not the owner. For these instances, each owner should be allowed to submit compliance reports reflecting each party's period of ownership. (VALERO1_69b-8)

> **Agency Response:** Staff appreciates the commenter's suggestion that regulated entities changing ownership might submit partial compliance reports for a compliance period. However, the LCFS program requires compliance to be demonstrated on an annual basis through annual report submission. Because several aspects of the program are built around an annual schedule – annual fuel pathway reports, annual crude oil reports, the Credit Clearance Market, annual verification statements – dividing annual reports would add administrative complexity in implementation of several parts of the regulation. Staff's proposed clarification of the LCFS compliance implications and procedures relating to change of ownership is designed to avoid any potential regulatory uncertainty and facilitate continuity and smooth transitions within the program for any regulated party changing ownership. With this clarification added, regulated parties changing ownership may be more fully on notice of preexisting requirements to coordinate necessary exchanges of data in order to allow the new owner to comply with LCFS reporting requirements.

N-5.2. Comment: We have concerns around the drafted change of ownership rules and which are elaborated on below.

1) A deal could fall through and ultimately not occur, but the change in notification would have already been made which would necessitate another change notification which will confuse the issue.

2) Entities in the deal may not legally be able to disclose prior to completion of the deal. Notification to CARB may violate an NDA, as well as possible state specific laws impact commerce; lastly, such provisions may be impossible to reconcile with SEC reporting requirements for public companies.

3) Notification to CARB would be of public record that by itself, may impact the ability to close.

If CARB were to require this notification paperwork to occur prior to the next quarterly submission of credits or within some reasonable time frame, say 45 days subsequent to the actual change in ownership, there would be no issue with the requirement. (REG1_88-9b)

Agency Response: Staff appreciates the commenter's insights and acknowledges the commenter's concern. Therefore, as part of the 15-day changes, staff proposed to allow up to 30 days for the previous and new owner of a registered entity or facility notification to CARB after a change of ownership of an entity or facility, in order to accommodate practical compliance concerns raised by the stakeholder. Staff believes 30 days would allow sufficient time for the previous and new owner to comply with the proposed requirements.

N-6. Multiple Comments: *No Retroactive Credit Claim*

Comment: In the LCFS program, there are three verification/validation overarching concerns: ability to correct previous reporting period errors, administrative penalties for minor accounting/recordkeeping/reporting errors/omissions, and variation in actual versus approved pathway CI values of low CI fuels.

WSPA is concerned that the current regulations may leave actual reductions out of obligated party compliance accounting, making it more difficult for such parties to comply. ARB's proposal prohibits retroactive corrections to previously filed quarterly reports. This would eliminate credits from over-reporting a previous quarter's obligation that could be credited if retroactive report amendments were allowed, leaving such credits "orphaned" and uncounted.

We are also concerned that minor accounting/reporting/recordkeeping errors and omissions, and small variations in verified CI values may result in administrative penalties as there is no mechanism for regulated parties to correct these small errors which they have expressed a desire to have. (WSPA1_21-14)

Comment: WSPA does not agree with ARB's assertion that current regulations prohibit corrections to prior reporting periods and objects to the proposed changes to write this interpretation into the regulations. Corrections to reports are not necessarily a sign of wrongdoing or violating regulatory requirements. Adjustments to transaction records are a normal part of doing business and reporting parties should not be penalized for wanting these adjustments reflected in their compliance reports. Even where such corrections are the result of recordkeeping or reporting error, it is unreasonable to withhold the full value of the corrections as an automatic penalty as it goes beyond normal enforcement discretion and can mean a significant financial impact for perfectly reasonable errors or oversights. (WSPA2_61-14)

Comment: Our industry prepares and submits required reports under many different state and federal regulations, involving millions of data points (production volumes, credit transactions, emissions, etc.). The reporting accuracy across the industry is very good, however, inadvertent errors do occur. When these happen, and are discovered, corrections are made. ARB is proposing to continue to disallow positive adjustments in the credit and deficit balances due to corrections. We strongly disagree with this approach. We ask that ARB change these provisions to allow individual regulated entities to capture any credits or reductions in deficits due to reporting corrections. (P661_55-4)

Comment: Chevron objects to the proposed change to § 95486(a)(2), where staff intends to codify their current interpretation of the restrictions on corrections to reports for prior periods. Data corrections are a routine part of business and compliance reports should be no exception. Billing errors, paperwork corrections, or simple clerical errors can result in the need to correct compliance reports after the deadline. By prohibiting beneficial corrections to previously-submitted reports, CARB is discouraging accurate reporting and unfairly penalizing reporting entities by confiscating valuable credits with no due process. We do not see how this change advances the goals of the LCFS or improves CARB's confidence in reporting accuracy. (CHEVRON1_112-6)

Comment: Kern strongly disagrees with ARB's proposal under Section 95486(a)(2) to prohibit any claim to retroactively generate credits or eliminate deficits for which a reporting deadline has passed. Such a provision unfairly denies a fuel reporting entity the adjustments to their credit bank and/or deficit obligation when simple, correctable errors are discovered and remedied during the annual third-party verification process. Kern understands ARB's desire to ensure maximum accuracy in reporting and avoid situations where fraudulent actions or simple reporting errors result in invalid credit generation. However, in light of the proposed requirement for third-party verification of quarterly fuel reports, this provision is unnecessary and unjustly punitive.

Kern urges ARB to reconsider this approach and work with stakeholders to develop a balanced and fair set of provisions that will satisfy the need for integrity and accuracy in reporting. As an example, Kern suggests the section could be rewritten to provide that no credit could be generated or deficit eliminated retroactively beyond the issuance of a positive or qualified positive verification. This approach would allow fuel reporting entities to make revisions for correctable errors discovered during the verification process, and fairly receive the credit/deficit adjustment commensurate with those corrections, in line with the intended, appropriate use of the verification process. (KERN1_115-3)

> **Agency Response:** Staff appreciates the commenters' inputs and would like to clarify that the current and the proposed LCFS regulation allows corrections to previously submitted reports as the program strives to ensure the accuracy of the reported data. However, pursuant to section 95486(a)(2) of the LCFS regulation as re-adopted in 2015, an entity may not retroactively claim credits or eliminate deficits for a period for which the reporting deadline has passed unless the credits were released from hold upon completion of fuel transport demonstration pursuant to section 95488(d) and (e), or are the result of an application completion pursuant to section 95489. This was intended to ensure fuel reporting entities have an incentive to report their data accurately and on time, as required by the LCFS rule. All reporting entities are required to upload quarterly data within the first 45 days after the end of the quarter and have another 45 days to reconcile their data with business partners before submitting it by the reporting deadline. Staff believes this provides sufficient time and opportunity to reporting entities to ensure the data submitted is accurate. This minimizes the instances of correction in credit balances of entities account which could

otherwise be administratively challenging for CARB and disruptive to the credit market.

Further, in this rulemaking, staff proposed to remove the fuel demonstration requirements in section 95488(d) and (e), and crediting provision in section 95489. To reflect those changes and to further clarify the prohibition on retroactive credit claim and deficit elimination, staff proposed changes to section 95486(a)(2).

In further response to the commenter's concern about report corrections in WSPA1_21-14, staff believes the proposed reporting structure provides necessary tools and sufficient time to reconcile and report the correct data during the reporting period. Once the reporting period is over, but prior to completion of verification services, the reporting entities with misreported data would need to fix errors or omissions identified by the verifier or CARB in order to come back into compliance in the program and be issued a positive verification statement.

N-7. Multiple Comments: *Proposed Fuel Transaction Reconciliation Requirements*

N-7.1. Multiple Comments: *Fuel Transaction Reconciliation Requirements*

Comment: In § 95486(a)(1)(B), a provision has been added whereby credits will not be issued if a credit generator has not fully reconciled the relevant transaction reporting with their business partners. WSPA supports and appreciates the formal report reconciliation process. It improves the accuracy of reporting and the overall stability of the program. However, we believe this proposed provision is overly punitive in that there is no recourse provided for a reconciliation effort that goes beyond a quarterly reporting deadline. This provision would allow a reporting entity to avoid transferring credits or accepting deficits by simply reporting an amount that is one gallon different from their business partner.

In that situation, ARB proposes to simply invalidate all transfers of a given pathway between the two business partners, regardless of which party reported correctly. ARB's stated position is that the wronged party in this situation would have legal recourse to correct the situation outside of LCFS reporting. That is an extreme solution to what may be a minor disagreement. We urge ARB to improve this provision by allowing partial transfers of credits and deficits to exclude only the difference between the reported volumes, establish a materiality threshold for reconciliation differences, and allow for prior-period corrections to be made once a reconciliation dispute is resolved. (WSPA2_61-15)

Comment: In § 95486(a)(1)(B), staff have added a provision whereby credits will not be issued if a credit generator has not fully reconciled the relevant transaction reporting with their business partners. Chevron fully supports and appreciates the formal report reconciliation process. It improves the accuracy of reporting and the overall stability of the program. However, the proposed provision is draconian in that there is no recourse

provided for a reconciliation effort that goes beyond a quarterly reporting deadline. This provision would allow a reporting entity to avoid transferring credits or accepting deficits by simply reporting an amount that is one gallon different from their business partner. In that situation, CARB proposes to simply invalidate all transfers of a given pathway between the two business partners, regardless of which party reported correctly. CARB's stated position is that the wronged party in this situation would have legal recourse to correct the situation outside of LCFS reporting. That is a cumbersome, costly and inefficient solution to what may be a minor disagreement. We urge staff to improve this provision by allowing partial transfers of credits and deficits to exclude only the difference between the reported volumes, establish a materiality threshold for reconciliation differences, and allow for prior-period corrections to be made once a reconciliation dispute is resolved. (CHEVRON1_112-8)

Comment: REG requests clarification around 95486(a)(1)(B). Does this mean that parties have to reconcile transactions "without obligation" in addition to those "with obligation"? The market has seems to have "worked out the kinks" in transactions "with obligation", but those "without obligation" are still very much in a work in progress especially since there was no way to reconcile "without obligation" transactions until a few months ago in LRT. Furthermore, there are still counterparties with small volumes below the rack who are not registered in LRT. Since those counterparties won't have to undergo audits, REG requests that CARB not withhold credits over unreconciled volumes on transactions "without obligation". (REG1_88-12)

Comment: We request additional guidance or clarification on § 95486. Generating and Calculating Credits and Deficits, and § 95486.1. Generating and Calculating Credits and Deficits Using Fuel Pathways. It is unclear when the term "if applicable" is applicable. The two sections can be read such that no credits can be issued if non-obligated fuel transactions do not reconcile between counterparties. We hope that is not the intent. Non-obligated transfers should not impact credit issuance.

The concern is that there can be problems with a true reconciliation with transactions that are done "without obligation". It's typically close, but may not match to the gallon. So, the concern is that a small discrepancy in non-obligated transfers would impact the larger and more valuable credit transactions side. This would be a major problem for industry. (LOVE1_73-5)

> **Agency Response:** Staff appreciates the commenters' support for the fuel transactions data reconciliation process in the LCFS. Staff believes an effective reconciliation process ensures accuracy of the reported data and minimizes the correction requests especially when multiple business partners are involved. In turn, this minimizes potential modifications to the fuel and credit data published based on quarterly reports.
>
> To further enhance the reconciliation process, staff proposed that credits and deficits would be issued only upon reconciliation of fuel quantity reported per fuel pathway code (FPC) using transaction types Sold with Obligation and Purchased with Obligation among business partner. This creates a system check in

LRT-CBTS, eliminating the need for third-party verification of fuel reported with these transaction types. Due to these changes, the scope of third-party verification of quarterly reports for liquid fuels, as proposed by the staff, was limited to fuels reported with transactions types including production, import, and export for liquid fuels. Staff believes this change would reduce the administrative efforts and cost associated with the proposed third-party verification requirements.

N-7.2. Multiple Comments: ***LCFS Reporting and Credit Issuance Timelines***

Comment: *§ 95486.1 Generating and Calculating Credits and Deficits Using Fuel Pathways*

REG remains adamantly opposed to credits being generated on the day after the reporting deadline per (b) unless those deadlines are moved up. We understand the desire to automate the reconciliation process in LRT with a system check, but if those volumes are going to be verified, this system check seems to be duplicative of verification. Furthermore, CARB staff has increased the scrutiny of reporting variances within LRT so we are not sure how much this system check will help.

As noted in prior comments, REG, and likely other stakeholders, have already invested a significant amount of time and resources on education of the timing of LCFS credit revenue recognition in our financial statements relative to fuel sales with both internal and external parties. Currently, there is a 1 quarter delay between fuel activity and credit generation (i.e. Q1 fuel sales generated credits in Q2). Under the proposal being considered, the delay would be 2 quarters (i.e. Q1 fuel sales wouldn't generate credits until July 1 or Q3).

One day makes a materially significant difference for financial reporting purposes especially considering the new revenue recognition rules being implemented by the Financial Accounting Standards Board beginning January 1, 2018. We would effectively be reporting LCFS credit revenue two quarters after the fuel that generated the credit has been delivered to our customer, creating a timing mismatch and introducing additional complexity in other regulatory filings and risk of confusion in our public financial reporting (i.e. SEC reporting). Therefore, in the strongest language possible, we encourage ARB staff to keep the system as is. Under no circumstances should the reconciliation period stretch beyond 1 quarter.

…

§95491. Fuel Transactions and Compliance Reporting,

As noted 95486, REG strongly advocates to keep the credit generation system as is. However, if it is changed so that no credits can be generated until after the reporting period is over, then we strongly recommend changing the reporting frequency and deadlines from 45/45 to 40/40 to avoid financial statement impacts. (REG1_88-15)

Agency Response: Staff appreciates the commenter's inputs and support for the proposed reconciliation process. Staff believes the proposed reconciliation process is critical to limit the scope of the third-party verification as proposed by staff and to ensure the accuracy and integrity of the data reported in the program. However, to implement the proposed reconciliation process and issue the credits and deficits for the reconciled data, the LRT-CBTS must be able to process all the submitted quarterly reports at once. Therefore, staff proposed credits and deficits would be generated only upon completion of the reporting deadline, as all the reports must be submitted by then. Staff does not believe the proposed change significantly affects the crediting cycle or is disruptive to existing business practices as most of the reports are submitted around the reporting deadline. The stakeholders participating in the LCFS program have invested significant resources and time in developing reporting tools based on the existing reporting timelines. Thus, staff did not propose changing the established reporting timelines which could be disruptive to existing business practices.

O. Third-Party Verification

O-1. Multiple Comments: *Support for the Proposed Third-Party Verification Provisions*

Comment: Element Markets supports the proposal to supplement the work of CARB staff with a third-party verification program and applauds the efforts of CARB staff to integrate the program with the U.S. EPA's Quality Assurance Plans under the Renewable Fuel Standard. (EMRE1_B16-1b)

Comment: In Section 95488 and elsewhere ARB outlines its decisions to utilize Third-Party Verification for tracking, monitoring and reporting GHG emissions at facilities. AMP supports this decision. ARB's aggressive Carbon Intensity Benchmarks will require significant growth in the number of credit generating facilities. To date, ARB has relied on internal staff to evaluate fuel CI and audit quarterly reports. (AMP1_86-4a)

Comment: Clean Energy views the verification proposal as a vital addition to the LCFS program… (CE1_92-6)

Comment: Clean Energy again appreciates Staff's initiative to strengthen the integrity of the LCFS program through the implementation of a robust verification program. (CE1_92-12)

Comment: What I want to raise the attention of the Board of is the proposed verification program. We see the verification program as a vital addition to the LCFS program, not only to strengthen the integrity of the program overall, but to provide additional liquidity into the market. (CE2_T5-2)

Comment: Chevron fully supports the addition of validation and verification procedures to the LCFS. (CHEVRON1_112-27a)

Comment: DTEBE supports the implementation of a third-party verification system for the LCFS program. Ensuring honest behavior and accurate reporting is of the utmost importance to maintain a healthy and stable LCFS program. Adding third-party verification will help to maintain the ongoing integrity of the LCFS program. (DTEBE1_56-5)

Comment: Enerkem is also supportive of CARB's introduction of sustainability verification by accredited third party verification/certification bodies.

…

We support … the introduction of sustainability verification. (ENERKEM1_135-6)

Comment: In particular, LADWP supports ARB's policy that no validation/verification of CI, except for pipeline-injected biomethane claims for renewable hydrogen, is required when using the Lookup Table pathways. (LADWP1_38-11a)

Comment: Neste renews its support that CARB authorize third-party verifiers, who are unrelated to the applicant, to perform due diligence on the proposed pathway applications and verify the CI modeling and calculations. The role of CARB staff would then be focused on oversight and verification. (NESTE1_76-9a)

Comment: Specifically we want to look at the verification program. Neste very much supports having a verification program in place that'll come in and give more reliability, more certainty, more transparency to that sort of process. (NESTE2_T11-2)

Comment: 9. NRDC strongly supports the inclusion of a third-party verification program to ensure accurate, robust reporting.

The LCFS is one of the world's most effective programs at incentivizing companies to lower the carbon-footprint of their products in a performance-based, data driven manner. As the value of the LCFS credit market has increased, and as the breadth of projects have grown, it is incumbent on ARB to create a verification system that enhances the program's integrity.

We support ARB's efforts to ensure that regulated entities generating more than a *de minimis* amount of reduction credits provide third-party verification around the data reported to ARB, including site-specific annual visits. We support ARB's efforts to also require independent third-parties to participate in training and to have no conflicts of interest. Doing so will allow the performance-based, technology neutral flexibility that ARB provides to allow for companies to credit their innovations and improvements, while enabling the administrative aspects to be handled in manageable fashion. (NRDC1_81-19)

Comment: The RNG Coalition SUPPORTS the intent of your proposal to supplement the work of CARB staff with a verification system that would require regulated entities reporting to CARB under the LCFS to retain the services of independent third-party verifiers. (RNGC1_16-3)

Comment: Second, we support the addition of third-party verification. (RNGC2_T43-3)

Comment: The verification piece. REG is supportive of verification. (REG2_T16-2)

Comment: EcoEngineers supports CARB's efforts to put in place a robust training program and clear qualification and conflict of interest standards for verification bodies and verifiers. (ECOENGINEERS1_B5-2)

> **Agency Response:** Staff appreciates the support for its proposed independent third-party verification program.

O-2. *Conflict of Interest and Availability of Qualified Verifiers*

O-2.1. Multiple Comments: *Firm Rotation Requirements, Availability of Qualified Verifiers, Lookback and Phase-In Period*

Comment: However, we disagree with CARB's approach of borrowing the standards for qualification, training and conflict of interest as-is from another program without thoroughly reviewing its applicability, utility and practicality for the LCFS. We believe there should be a review of specific components of the requirements for verification bodies and the conflict of interest provisions for their applicability to LCFS verification services. (ECOENGINEERS1_B5-3)

Comment: Additionally, our members have serious concerns about whether a sufficient number of verification firms are available to fulfill the requirements as proposed by CARB and the forced rotation of these firms, factors which undermine competitive lowest-cost engagement pricing.

ACE members are strongly opposed to mandated firm rotation. CARB insists the purpose of the firm rotation requirement is to ensure impartiality. We believe impartiality can be achieved by instead requiring rotation at the partner or lead verifier level within the firm. Accounting firms currently registered to complete Securities and Exchange Commission audits are required to rotate audit partners and this is a reasonable approach for CARB to implement for the LCFS. We also believe the detailed accreditation requirement and CARB approval of verification plans and sampling strategies are sufficient to ensure impartiality. Mandated firm rotation seems in direct contradiction to CARB's desire to leverage efficiencies amongst existing stakeholder verification programs. Forcing new firm engagement also increases the time and opportunity cost for pathway holders such as ethanol plants to inform and prepare the new auditors and firms about processes and practices. This will result in a loss of engagement efficiency and overall dissatisfaction of the verification experience.

Mandatory firm rotation is not only problematic for regulated parties but also for auditors and verifiers who will already be required to become accredited and incur the associated cost of undergoing the necessary training and travel. Once accredited, the verifier will experience a forced reduction in revenue in "off" years due to loss of clients and resulting in the likelihood of higher base fees. This higher cost structure will ultimately make its way to California fuel consumers, undermining program cost containment efforts. Again, ACE members urge CARB to incorporate either a voluntary third-party verification system on a trial basis or partner rotation in lieu of a firm rotation requirement for LCFS verifiers.

While we appreciate CARB's experience with mandatory verification through the Cap and Trade Mandatory Reporting Rule (MRR), our members maintain there are significant differences between Cap and Trade and the LCFS. For example, each LCFS pathway will have already undergone an initial validation. LCFS verification, unlike MRR, further requires pre-submission of verification plans and sampling strategies. This requirement will inherently offer CARB the ability to gauge the

adequacy of applied verifier program knowledge, verification design, scope, and strategy to identify potential errors up front.

ACE members are also concerned with the practical ramifications of the proposed conflict of interest and lookback provisions of mandatory third-party verification. We recommend CARB revisit this issue, narrow its scope, and refer to the independence standards established by the American Institute of Certified Public Accountants which are widely recognized as trustworthy and impartial.

We do not support the five-year lookback period for conflict of interest because it adds insult to the firm rotation injury requirement discussed above. ACE members are concerned a five-year lookback from 2022 retroactively penalizes the regulated parties that may have implemented third-party-assurance programs prior to this rulemaking. Section 95503(b) provides that any number of activities performed by a potential verifier will result in their disqualification subject to firm rotation requirements. The list of potential conflict activities that require mitigation is broad and would unfortunately reduce the pool of the most competent verifiers. Our members are also concerned about a number of provisions which would disqualify potential firms if they participated in any sort of design consulting related to a facility such as information technology, engineering analysis, construction consulting, internal audit procedures, and health and safety assistance. As proposed by CARB, there is no time limit for these activities so if anyone on the verification team ever did any of the activities at any time in the past, then they are deemed to have a conflict. This is unreasonable. (ACE1_41-4b)

Comment: A specific element we object to is the firm rotation requirement. We do not believe this is necessary and have found the requirement to be disruptive under the MRR verification program, without adding accuracy or information security. With a limited pool of verification firms, it has been challenging to select firms, even on a six-year rotation. Participation in audit engagements by CARB staff will enable staff to "audit the auditors" without any specific mandate to rotate firms. It is worth noting that major corporations retain the same accounting firms for many years to conduct required audits of their financial statements, an area with far greater risk and exposure than the MRR or LCFS. (CHEVRON1_112-31)

Comment: We recommend CARB consider taking additional steps to ensure the pool of qualified third parties for verification services are not reduced. The Conflict of Interest, Firm Rotation and Lookback provisions will considerably reduce the pool of "qualified" parties capable of meeting the criteria. Many of the most qualified companies will be excluded from the pool based on the proposed set of new requirements, which in turn will impact pricing for such services and potentially the credibility of the program by effectively mandating the use of with "less qualified" verifiers.

Our concern regarding the Conflict of Interest and Rotation is with level of expertise in this new and highly specialized market and the risks associated with a less than "highly qualified" verifier pool. We go to great lengths to ensure the firms we use to verify our pathways are credible and experienced. This saves time, money and helps to ensure the integrity of the LCFS program. Limiting the qualified pool of verifiers with the

proposed conflict of interest provisions and required rotations runs counter to the integrity of the LCFS program. *We request the elimination of the firm rotation requirement, the initial look back period associated with the Conflict of Interest provisions and requirement for annual site visits by verifiers.* (LOVE1_73-2)

Comment: Verification costs will be inherently inflated by the proposed regulation's limitations on the number of active verification bodies and the onerous forced firm rotation requirement. Both of which work against competitive lowest cost engagement pricing. (RPMG1_64-14)

Comment: RPMG remains opposed to mandated firm rotation[4]. Partner or lead verifier rotation is a sufficient alternative. RPMG strongly believes mandated firm rotation is in conflict to CARB's and stakeholders' mutually beneficial desire to leverage efficiencies amongst existing stakeholder verification programs.

[4] September 7, 2017 Comments: https://www.arb.ca.gov/fuels/lcfs/workshops/11032017_rpmg.pdf
October 6, 2017 Comments: https://www.arb.ca.gov/fuels/lcfs/workshops/10062017_rpmg.pdf;
November 3, 2017 Comments: https://www.arb.ca.gov/fuels/lcfs/workshops/11032017_rpmg.pdf

CARB has stated their interest in incorporating a firm rotation requirement is to ensure "fresh eyes" and impartiality among firms. The stated benefits of mandated rotation by CARB can be achieved at the partner or lead verifier level. RPMG believes the program's detailed accreditation and CARB approval of verification plans and sampling strategies are sufficient to ensure impartiality.

CARB further elaborates this requirement has been successfully demonstrated through administering the Mandatory Reporting Rule (MRR) under Cap and Trade. RPMG maintains there are crucial differences between Cap and Trade and LCFS. Each LCFS pathway will have undergone an initial validation. LCFS verification, unlike MRR, further requires pre-submission of verification plans and sampling strategies. This requirement will inherently offer CARB the ability to gauge the adequacy of applied verifier program knowledge, verification design, scope and strategy to identify potential errors up front.

Required firm rotation does not adequately allow for a regulated entity to consider a verification body's basic knowledge of an industry or individual business practices. This will result, without question, in a loss of engagement efficiency and overall dissatisfaction of the verification experience. Regulated entities have commercial operations to manage. Excessive time spent on repeated and recurring introductions of a new auditor to those operations is not an effective use of enterprise resources, and it will amount to a loss in productivity and increased costs—costs not considered by CARB. This is unnecessary for all involved. Creating this climate as the foundation for verification interaction is only going to result in strained relationships between the verifier and the stakeholder community.

A firm rotation requirement is not only problematic for regulated parties but also for verifiers. Verifiers already will be required to become accredited and will incur the associated cost of undergoing the necessary training and travel. Once accredited, the verifier will experience a forced reduction in revenue in off years due to loss of clients and resulting in a necessitation of higher base fees. This inflated cost structure will

ultimately make its way to California fuel consumers, undermining program cost containment efforts.

For all of these reasons, RPMG urges CARB to incorporate a partner rotation requirement in lieu of a firm rotation requirement for LCFS verifiers. (RPMG1_64-15)

Comment: The five-year lookback period for Conflict of Interest should be removed as they exacerbate the firm rotation requirements highlighted above. RPMG also remains concerned with the practical ramifications of the proposed Conflict of Interest and Lookback provisions. We recommend staff revisit this issue and narrow its scope.

A five-year lookback from 2022, is in essence retroactively penalizing the regulated parties that have implemented third party conducted assurance programs prior to this rulemaking. Section 95503(b) provides that any number of activities performed by a potential verifier will result in their disqualification subject to firm rotation requirements. The list of potential conflict activities that require mitigation is very broad and will certainly impact the pool of the most competent verifiers. (RPMG1_64-16)

Comment: The rulemaking requires that verifiers be certified by the Executive Officer and that verifiers rotate on a regular basis. This rulemaking is new to the LCFS and therefore no existing verifiers are currently available. The domestic ethanol production capacity is 15 billion gallons while California's consumption of that domestic production is less than 8%. CARB has asserted that financial verification bodies could provide these services given that they elect to be certified under the certification process laid out in the rulemaking. Unlike financial verification, which is universally required and widely available, verification for the LCFS will represent an extremely small volume of work. CARB may find that few assurance firms will want to participate in these services because of the limited amount of work and the additional hassle of obtaining CARB certification. Due to the potentially small pool of verifiers that will be available in the early years of this rulemaking for verification, producers may not be able to rotate through verifying bodies as required. Additionally, many domestic renewable fuels producers participate in Quality Assurance Programs under the RFS. These participants have for years contracted verifiers that could be potentially disqualified from verifying under the LCFS rulemaking because they have been engaged by the producer prior to the effective date of the rulemaking which would further limit the number of potential verifiers available. We therefore suggest that ARB change the requirement for rotation separation from three years to one year or provide for a means of exemption from the requirement if the number of registered verifiers is too limited to reasonably implement this portion of rulemaking. (WE1_78-2)**.**

Comment: We are also concerned that a few parties may be qualified to perform such services. To our knowledge, the few firms that are qualified already provide such verification services for most RNG producers and transportation fuel marketers. The proposed conflict of interest provisions have the potential to remove knowledgeable

parties as resources in the market, further driving up costs and unreasonably restricting verifiers from working on unrelated projects. (RNGC1_16-5)

Comment: The final conflict of interest item that we would like CARB to consider is the formation of new entities. If the conflict of interest items are not adjusted to allow more room for mitigation plans and offering of other services, then the solution that has been discussed within the industry and with CARB staff is to form a new entity to handle LCFS verification services. If a new entity is formed following CARB's guidelines for minimum employee requirements, and ensuring there is no related party ownership issues, we would still be individually contracting employees from Christianson to assist with the verification work. This means that, realistically, we would go through the work of creating a new entity and maintaining the paperwork, insurance, etc., but would actually be using the same employees that CARB is not allowing under the current proposed rules. In order to save money, time and paperwork, we urge you to seriously consider applying the high conflict items to only the verification team for a particular regulated party and allowing the conflicts at the firm level to be mitigated.

Firm Rotation

We have previously stated in numerous public comment letters that we believe the firm rotation requirements should be removed from the proposed rule and continue to support that opinion. At the same time, we do understand that it is helpful to have someone new review audit and verification data, and we would support a lead verifier rotation on the LCFS verifications.

In past letters, we have cited numerous reasons why the firm rotation is not necessary for this proposed rule. The additional auditor independence, objectivity, and professional skepticism gained from a firm rotation does not outweigh the substantial cost, efficiency, and effectiveness lost. The Public Company Accounting Oversight Board (PCAOB) has done extensive research on this topic, which included auditing certified public accounting firms and collecting a vast amount of data supporting their stance of only requiring audit partner rotation.

They have noted that most of the errors that go unnoted were due to lack of technical competence or experience, insufficient supervision or deficiencies in the firm methodologies, not pro-client bias going into the engagement.

Additional support for the PCAOB's findings comes from our own experience with the RIN Attest Engagements required by the US EPA. Often times when we obtain new clients for the RIN attest, we find errors that the previous auditor did not. This is generally due to a lack of technical knowledge and experience, or difference in procedures being completed from firm to firm with no EPA oversight. CARB has already mitigated these factors by requiring a sampling plan that notes the risk assessment, list of documents to be tested, and many other audit planning items. CARB can review these plans at any time upon request and can view the actual procedures being completed and address any deficiencies with the verification body. CARB will also be requiring verification body team members to complete a CARB

hosted training and test to become accredited prior to providing verifications. This accreditation process will mitigate the lack of technical knowledge and experience problems where errors are normally found upon rotation.

CARB has also reserved the right to audit the verification bodies. If there are concerns with long-standing relationships, we would suggest that CARB specifically choose some of these verification reports to audit so that they can ensure that the long standing relationship is not having an effect on the auditor's independence or professional skepticism. If CARB feels that there is a bias in the procedures being performed due to the relationship, then rotation could be required at that time. Finally, we also wanted to call attention to the limited effect the firm rotation will have for the verifications. It is very likely with the limited pool of verifiers that the regulated parties will identify two firms that they are comfortable with and will rotate between those two firms. This means that there are essentially two audit teams that they will always work with and will get limited exposure to new firms and new procedures. This limited benefit is not worth the added cost and lost effectiveness of the verifications through firm rotation. Including a lead verifier rotation would provide a new look at the data while still maintaining the verification team staff and the efficiencies gained with their knowledge and experience with the regulated party. (CHRISTIANSON1_27-3)

Comment: Each year, the verification body will be required to audit two years of data maintained for the GREET model. We would like to suggest that CARB consider adding an option of doing a predecessor review of the prior year's documentation so that procedures do not need to be redone on the prior year numbers when a new client is obtained by a verification body.

This would work similar to financial statement audit requirements, where the new verification body would work with the prior verification body to arrange a time to review the prior year's audit file to become comfortable with the accuracy of the prior year numbers rather than redoing audit procedures on the prior year data. This would save both the verification body and the regulated party time and money by not having to completely verify all the prior year numbers for a second time. (CHRISTIANSON1_27-6)

Comment: REG has consistently maintained that CARB should follow well established auditing guidelines by FASB, SEC, or Treasury Dept. We continue to have very strong concerns about firm rotation. Rather than repeat them here, we will simply support the comments submitted by our RFS attest auditors, Christianson & Associates. (REG1_88-28)

Comment: We're a little bit concerned with how the proposal moves forward and that we were afraid we might not get the pool of verifiers that we need. And that is a critical item that needs to be addressed. (REG2_T16-3)

Comment: Growing pains, those that come with years of developing solutions to meet the ever-evolving requirements under the U.S. EPA's Renewable Fuel Standard (RFS), Environment Canada's Renewable Fuels Regulations (RFR), the Renewable Energy Directive (RED) in Europe, and the International Sustainability and Carbon Certification

(ISCC) scheme, have made us painfully aware of the fact that there exists a very limited number of people and firms that are truly knowledgeable enough to provide specialized audit, verification, and support services in this arena. As Murex seeks to take proactive measures to ensure the readiness of all our LCFS approved facilities once this proposed rule goes into effect, our level of concern grows over a few of the proposed requirements of verification bodies under the LCFS program. Specifically, we do not feel that there are enough parties with the expertise and qualifications necessary to properly conduct the sought-after verification services while also complying with the firm rotation and conflict of interest provisions within the rule as currently written. Fortunately, there are alternative remedies that would protect the original intent of the program while preventing the potential for egregious errors and inadvertent non-compliance resulting from engaging the services of individuals or firms lacking adequate experience in renewable energy initiatives.

On the topic of firm rotation, because the number of firms specializing in renewable energy services are limited, long standing business relationships with the clients to whom they provide services is a natural and positive result. Engaging the services of the same firm on an ongoing basis results in beneficial efficiencies and cost savings. Not only is the firm already well-educated on the renewables front, but its comprehensive understanding of the client's business models, processes and procedures, and systems provides for highly effective and timely engagements less prone to error due to differences in interpretation and methodology or a general lack of understanding of the business in question. Further, in many cases, auditors have already collected, analyzed, and stored the applicable data, documents and records for clients that are subject to multiple regulations across the country and the world. Instead of rotating firms, a more practical approach would be to rotate audit staff and/or team leads within the firm. Beyond the aforementioned potential for errors, switching firms every two years would cost more money and consume much more time and human resources, adding several more months to the engagement, and possibly missed deadlines.

Regarding conflicts of interest, we find that specialized renewable energy audit firms, provide a variety of services unique to our industry and that are a natural progression and extension of the firms' service offerings. While a non-specialized audit or CPA firm may not have enough experience to conduct an appropriate renewable energy engagement, that is not the case in reverse. These firms have been committed to gaining their renewables expertise over years of education and industry interaction. For practical reasons, many stakeholders would rather keep their financial and regulatory audit requirements all within the same firm that has already established independence, largely due to the synergies created when overlapping data can be applied to multiple engagements. (MUREX1_60-1)

Comment: In closing, since CARB will already be auditing the verification bodies, it should be easy enough to conduct procedures that establish auditor independence, as well as an absence of bias and/or conflict of interest. (MUREX1_60-5)

Comment: While we understand the intent behind the draft provisions requiring that fuel pathway holders submit to third-party validation and verification services, we are concerned by several aspects of these planned amendments. An overarching concern with the proposed fuel pathway and fuel transaction verification program is that it appears to be based primarily on the mandatory GHG reporting regulation (MRR) and California GHG cap-and-trade program. These are very different programs with different regulated entities, and the reporting/verification regimes that may work well for MRR and cap-and-trade may not be appropriate for the LCFS. Our specific concerns are outlined more fully below.

A. The proposed verification body rotation requirements are unwarranted and may actually lead to more—not less—verification errors and uncertainty.

There are a limited number of firms with the necessary expertise and experience to perform quality verification and validation services for low-carbon fuel pathway holders. The proposed verifier rotation requirements may force ethanol producers to periodically switch away from using qualified, knowledgeable verifiers to using verifiers with less experience regarding the LCFS program and ethanol production processes.

We believe frequent switching of verification bodies could increase the opportunity for auditing errors, as new verification bodies will be less familiar and less informed on the operations of fuel pathway holders. We recommend that CARB eliminate the requirement to entirely rotate verification bodies, as the requirements for verifier accreditation, training, and submittal of a verification plan already mitigate against verification errors and non-compliance. That said, CARB's proposed accreditation requirements appear excessive and may further reduce the pool of available qualified verifiers, thus reducing efficiency and raising costs for fuel pathway holders.

In lieu of requiring rotation of the firms performing verification services, CARB could instead require rotation of the lead auditor. We believe CARB could accomplish its goals by allowing the same verification body to be used without rotation, but requiring that the person in charge of the audit must periodically rotate. (RFA1_80-15)

> **Agency Response:** Staff believes there will be a sufficient number of qualified verification firms in time for implementation of the verification program and on a continuing basis. The proposed third-party verification component of the LCFS regulation seeks to leverage CARB's extensive experience in implementing verification and accreditation programs. While the proposed LCFS verification program is based upon the Cap-and-Trade and MRR verification programs, staff proposed some modifications when necessary, including for accreditation and phase-in of conflict of interest provisions. Please see Response O-5 in this chapter regarding the suggestion to consider a voluntary verification program on a trial basis.
>
> To address concerns regarding the availability of verification bodies in the program, staff has included requirements in section 95502 for fast tracking accreditation for firms currently providing biofuel auditing services under the U.S.

EPA RFS including the voluntary Quality Assurance Plan (QAP) program, international certification systems recognized under the European Union's Renewable Energy Directive (EU RED), and for CARB-accredited verifiers under its existing programs (MRR and offsets). Staff expects these firms to seek CARB's fast-track accreditation training, providing a pool of qualified verifiers prior to verification being required. As part of 15-day changes and in response to stakeholder comments, staff also included a phase-in period for several high conflict services in section 95503(b) to smooth the transition for verifiers currently active in these other programs.

As described in the ISOR, staff's proposal provides for phase-in of the verification program, beginning one year after the regulation would become effective, to continue staff outreach to auditing firms. Staff encourages alternative fuel producers and importers to work with their RFS or EU RED auditors to become accredited by CARB to perform LCFS verification services. Staff has been in discussions with biofuels and greenhouse gas auditing firms through the extensive stakeholder process thus far. Staff expects the largest and most active auditors in the U.S. EPA Renewable Fuel Standard (RFS) Program to participate in the LCFS program, as well as the verifiers already participating in CARB's other verification programs. Staff has also reached out to auditing firms providing international biofuel certifications under the International Sustainability and Carbon Certification system (ISCC), Bonsucro, and the Roundtable on Sustainable Biomaterials (RSB) to consider applying for CARB accreditation to provide LCFS verification services. Staff continues to reach out to potential verifiers to ensure sufficient qualified verifiers are available to provide LCFS verification services and will continue to do so to ensure the number of qualified verifiers and firms does not constrain regulated entities meeting rotation requirements.

Quality, independent verification services are necessary for public and market confidence in reported LCFS data. Staff maintains that the integrity of CARB's carbon markets requires automatic verifier <u>and</u> firm rotation with a meaningful break in service before reengagement. Firm rotation provides two benefits—it protects against organizational pressure to maintain long-term client relationships (i.e., pressure to avoid submitting an adverse verification statement) <u>and</u> results in a new set of eyes to review data submitted by the reporting entity. This requirement will reduce complacency that may occur given the comfort and familiarity a verification body may feel toward a reporting entity after an extended time period. Rotation of individual verifiers, without the rotation of the firm, could perpetuate a culture of familiarity or lack of professional skepticism. While CARB will institute a rigorous oversight program for auditing select verifications each year, and staff would be able to detect lack of verification rigor during on-site observations and deck reviews, detecting an increase in general complacency on behalf of the verifiers that reduces the overall effectiveness of the verifications over time may be more difficult to detect; therefore, automatic firm and verifier rotation is needed.

Staff did not change the proposed firm rotation requirement and disagrees that verification team member rotation or partner rotation as suggested by the commenters provides the same level of impartiality as an automatic firm rotation. The six-year rotation requirement will protect against organizational familiarity or pressure to maintain long-term client relationships that can erode impartiality and may be difficult to detect.

While staff agrees with commenters that fresh eyes can also be achieved by rotation of verification team members or rotation of the audit partner as is required in public financial accounting, such as the American Institute of Certified Public Accountants, this is insufficient to address organizational pressure to maintain long-term client relationships. Staff believes that limiting the period of engagement to six years, with a meaningful break of three years before reengagement, is necessary to avoid real and perceived conflicts of interest from lengthy business relationships between verifiers and their clients. For these reasons, a one-year break would be insufficient, as proposed by one commenter. Given CARB's experience with implementing its current verification programs, staff expects that verification bodies would be able to switch clients under the mandatory rotation and effectively bring their knowledge of similar and different data systems to bear during verifications with the new clients. Current longstanding relationships between LCFS participants and firms providing QAP and RIN attest services may be perceived as a barrier to entry to other firms who can build expertise and provide for more competition for auditing services, thereby providing a check on cost inflation. In addition, responsible entities can reduce onboarding time for new verifiers, and potential associated cost of rotating verification bodies, by continually improving their monitoring plans, internal controls, and recordkeeping.

As suggested by commenters, rotating between two firms with three to six year breaks in service would address the perception of familiarity or management pressure on the team to render a favorable verification statement. Staff's proposal requires verification body and verifier rotation every six years, not every two years, and should provide enough time to realize efficiencies.

The separation of management and verification teams under two different companies, as suggested by one commenter, would be expected to address the perception of familiarity or management pressure on the team to render a favorable verification statement. Using the same employees would be prohibited under staff's proposal if individual verifiers had high potential for conflict of interest during the five-year lookback period.

Staff understands that LCFS participants have various requirements that necessitate the need for third-party auditing services, some of which involve overlapping review of data common to the various audits. Staff's proposal would allow entities to utilize the same firm to conduct multiple audits, essentially stacking the multiple financial and regulatory audit functions to include LCFS requirements. This would allow the same firm to review like-data under the

various programs until firm and verifier rotation is required in the LCFS program—up to six years.

Staff's proposal for fuel pathway applications to undergo third-party validation is necessary to reduce risk of later LCFS credit invalidation, since LCFS credits for alternate fuels are issued prior to annual verification of historical carbon intensity data. Issuing credits prior to verification of historical data is unique to the LCFS. CARB's Cap-and-Trade program issues offset credits after verification of historical data.

CARB would not pre-approve client-specific verification plans and sampling strategies; therefore, this would not protect against bias from familiarity. Instead, firms applying for accreditation by CARB to conduct LCFS verification services would include verification templates with their application materials as evidence of competency, but these would not be specific to particular regulated entities nor require approval by CARB.

A lookback period for assessing conflict of interest is necessary to establish the relevant time period for which services are disclosed and assessed to ensure impartiality. Commenters have raised concerns that the lookback period for evaluating high conflict services will limit the number of qualified verifiers available to perform verification services. There is no unlimited or indefinite lookback period for disclosure of services and self-assessment of conflict of interest as indicated by some commenters. Staff's proposed lookback period is five years and has been successfully implemented CARB's other verification programs. To address commenters concerns, staff originally included and then extended a "phase-in period" that would allow specific high-conflict services to be mitigated as medium risk until August 31, 2023, to allow for completion of verification of 2022 data before requiring rotation of verification bodies. Staff believes these specific activities pose less risk to impartial verification if limited to the phase-in period and are effectively mitigated. CARB staff will provide additional oversight to confirm that mitigation plans submitted under the phase-in are sufficient, as stated in the ISOR. This is intended to provide a smooth transition while verification bodies and their current clients plan for a rotation of verification bodies in 2023. Staff will monitor the availability of verification bodies within the phase-in period to ensure sufficient qualified verifiers are available to provide LCFS verification services.

Commenters have expressed general and specific concerns about the stringency and scope of CARB's list of high conflict services. These comments are generally addressed here and more specifically in Responses O-2.2 and O-2.3 in this chapter. Competent auditing firms have made specific suggestions to clarify certain high conflict of interest provisions and staff has made targeted changes to its original proposal in light of these comments. These targeted changes would ease initial implementation and provide opportunity for detailed staff review of services that will be disclosed in conflict of interest self-assessments during the phase-in period, while providing consistency over the long term with CARB's

other verification programs. Staff has not included developing internal audit procedures (section 95503(b)(2)(D)) or directly managing health and safety (section 95503(b)(2)(F)) in the proposed phase-in period, as staff is concerned the potential for conflict of interest could not be sufficiently mitigated if the verifcation body has been in the role of outsourced staff to the client or would be verifying their own work.

Staff understands that predecessor review can increase audit efficiency for financial audits when a new audit firm is engaged, but would not allow this practice for LCFS verification. A Fuel Pathway Report, even though it contains operating data from a calendar year that would have been verified by the prior verification body (e.g., prior to rotation), must be subject to the current verification body's risk assessment, sampling strategy, direct data checks, and audit documentation transparency required for independent review. Audit documentation transparency is important for CARB's verification oversight program.

Commenters expressed a variety of concerns that could lead to increases in verification cost. Staff is mindful of verification quality, efficiency, and the potential for cost inflation. Staff addressed these concerns by clarifying that regulated entities may rotate between two separate verification bodies with 3-year breaks between 6-year engagements; extending and enhancing a phase-in period for high conflict services for smooth transition; and describing the fast-track accreditation option for firms currently providing biofuel auditing services in similar programs with a remote training component to avoid travel costs.

Please see Response O-4 in this chapter regarding concern about annual verifier site visits expressed in comment LOVE1_73-2.

O-2.2. Multiple Comments: *High Potential Conflict Categories*

Comment: Likewise, there are a number of subparagraphs which disqualify potential firms if they participated in any sort of design consulting related to a facility—information technology, engineering analysis, construction consulting, internal audit procedures, health and safety assistance. There is no time limit for these activities, i.e. if <u>anyone</u> on the verification team ever did <u>any</u> of the 20+ activities at <u>any time</u> in the past, then they are deemed to have a conflict. (RPMG1_64-18)

Comment: Christianson PLLP employs 50+ people and provides a number of different services within the renewable fuels industry. Our financial audit service team typically requires 5-6 employees for a single engagement, which is the largest team our services require. Since any one engagement requires at most 5-6 employees, there is ample room to build additional firewalls and mitigate potential conflicts while still maintaining familiarity with the client and gaining efficiencies through data collected during other services. To require the entire firm of 50 people to meet all conflict of interest requirements would disqualify us for a number of our normal clients.

We would like to suggest that the services noted as high conflicts only be prohibited if someone on the LCFS verification team for a particular entity is completing one of those services. If the verification body firm is completing those services, we would suggest they be noted as a medium level conflict where we can provide a mitigation plan explaining to CARB the firewalls in place, including using separate staff for various services. In addition to allowing us to complete a mitigation plan, CARB could also require a disclosure of any concentrations, where the total revenue from a particular client makes up 10% or more of total firm revenue. Where concentrations are present, it would indicate that there is potential for false positive statements on LCFS verifications in order to maintain other work. As long as the client is not a concentration to the firm as a whole, then revenue percentages should not make a difference in independence evaluations. (CHRISTIANSON1_27-1)

Comment: CARB seems to believe that any verification body that also offers consulting service to the same client is at risk of being in high conflict. CARB seems to be partial to "pure play" verification bodies as the preferred vehicle to conduct validation and certification work. CARB further seems to believe that the lure of selling consulting work will compromise a verification body's impartiality. We disagree with CARB's beliefs on this matter. CARB should not assume that a diversified company that offers consulting and auditing services is inherently pre-disposed to be biased or is at greater risk of being biased relative to companies that only offer verification services. A diversified company offering both verification and consulting services can perform quality, impartial validation, and, conversely, a company that only provides verification can be biased and/or tempted to compromise the quality of their validation.

EcoEngineers provides consulting and verification services to the biofuels industry. Our multiple business offerings and our broad client base mean that our future is not beholden to maintaining one client or one service. We are more likely to deny certification and lose a future stream of revenue than someone exclusively dependent on one service offering or a handful of clients. We urge CARB to take a broader view of this issue and allow greater flexibility for verification bodies to provide auditing and consulting services. Not doing so will also have the negative side effect of limiting the availability of experienced auditors, who may be working for a diversified company, to perform LCFS verification services.

We recommend that the conflict of interest provisions be limited to individual verifiers and verification teams, and not to verification bodies. We recommend CARB allow verification bodies to create isolated teams dedicated to performing verification for a specific client, and concurrently have separate consulting teams that offer consulting services to the same client. It will be up to the verification body to demonstrate, and for CARB to review and approve, how it intends to keep these teams' decision making independent of each other. (ECOENGINEERS1_B5-4a)

Comment: (1) *Conflict of interest requirements.* We propose that the types of services that create a high potential of conflict of interest be divided into two tiers – the first comprising services that may be provided by a verification body or employee during the lookback period but not a member of the verification team itself (i.e. that mandate

rotation of the verification team members rather than the firm itself) and the second comprising services that may not be provided by the verification body or employee at all during the lookback period (i.e. mandating rotation of the verification body entirely). Additionally, we propose a clarifying modification to Section 95503(b)(2)(U). (EMRE1_B16-1)

Comment: From a practical perspective, however, we are concerned that the conflict of interest provisions of the Proposed Regulation are likely to severely limit the ability of responsible entities to find and retain qualified verifiers at a reasonable cost.

Section 95503(b)(2) outlines certain services that, if provided to a responsible entity by a verification body or employee of a verification body at any time during a five-year lookback period, would constitute a high potential for conflict of interest and preclude the verification body from performing verification services for the responsible entity. It is increasingly likely that Section 95503(b)(2) will apply in some way to any large responsible entity or verification body, or to any responsible entity or verification body that has a longer history in its respective industry. To avoid this result, we propose that the list of services in Section 95503(b)(2) be bifurcated into two tiers – Tier I and Tier II. Tier I services would constitute a high potential for conflict of interest only if provided by a member of the proposed verification team during the lookback period, while Tier II services constitute a high potential for conflict of interest if performed by the verification body or an employee thereof during the lookback period. (EMRE1_B16-1a)

> **Agency Response:** To protect verification impartiality, as stated in the ISOR, "The proposed regulation includes prohibitions such as providing services that would be considered verifying one's own work, advocating for the client, advising the client on compliance strategies, or having a commercial or financial interest in verification outcomes." Services in these categories would be prohibited at the firm level due to the potential for management pressure on the team to render a favorable verification statement; therefore, staff did not bifurcate the list of services in section 95503(b)(2) between team-only conflicts versus firm conflicts as suggested by commenters. Conflicts that apply only to verification team members are already provided for under the category of medium risk in section 95503(d) and may be mitigated. When the concern is limited to verifying one's own work—whether the firm's work or an individual's work—the provision clarifies those services that are allowed when the results of the service would not be part of the LCFS verification.
>
> Staff appreciates the suggestion to monitor concentration of work as evidence that organizational pressure to render a false positive verification statement may be mitigated and would welcome verification bodies to include this disclosure in their self-assessment of conflict of interest provided to CARB.
>
> Please see Response O-2.1 in this chapter regarding concern about verification costs and sufficient qualified verifiers due to proposed conflict of interest provisions. Please see Response O-2.3 in this chapter for comment

EMRE1_B16-1c regarding expert services under section 95503 (b)(2)(U) referred to in comment EMRE1_B16-1.

O-2.3. Multiple Comments: ***Specific Conflict of Interest Requirements***

Comment: B. CARB's proposed conflict of interest requirements are excessive and may disqualify reputable and experienced firms from serving as verification bodies.

CARB's draft provisions require potential verification bodies to conduct a conflict of interest (COI) self-assessment and submit it to CARB for review prior to offering verification services. Among the activities considered by CARB to constitute a "high conflict of interest" are providing bookkeeping, other accounting services, or accounting software/automation support to the company requiring verification services. We do not believe firms that serve as verification bodies should be barred from providing financial accounting or other related services to the pathway holder, as numerous safeguards and independence requirements are already in place to mitigate against any potential conflicts of interest. At a minimum, CARB should reclassify these situations as "low" or "medium" risk and allow verification body applicants to provide a mitigation plan explaining how potential COIs will be mollified. (RFA1_80-17)

Comment: If CARB is not agreeable to the suggestions in the paragraph above, then we would like to discuss permanently moving <u>§95503(b)(2)(C) Service related to development of information systems, including providing accounting software or consulting on the development of environmental management systems, unless those systems will not be part of the validation or verification process</u>, to a medium conflict. Typically, the software and support services provided for clients are done by a completely separate department that does not include accounting staff that work on general services or compliance verification type services. These service teams act within the firm like they are two separate entities even though they are held under a single firm name.

There are already a number of firewalls between these departments of the company to help maintain our professional independence for other audit services and, therefore, we should be able to mitigate this conflict with CARB as well.

There is also a high conflict of interest item that we believe needs further definition. Currently, the proposed regulations notes the following as a high conflict item:

<u>95503(b)(2)(N) Bookkeeping or other services related to accounting records or financial statements;</u>

The wording for this high conflict item is very vague and would imply that anything having to with the financial statements would be excluded. We would recommend updating the text for this high conflict item to state, **"Bookkeeping and other non-attest services related to accounting records or financial statements, excluding services and results of those services that will not be part of the validation or verification process."**

Attest services are services that only a Certified Public Accountant (CPA) can perform and generally include audit, review and compilation of financial statements and agreed upon procedures (the RIN attest), among other services, most of which require independence. These services are unique to a CPA because they require passing the Uniform CPA Examination, adhering to a strict code of ethics, complying with professional standards and meeting ongoing professional development and education requirements. Many of these services require independence with the client, and we have therefore already demonstrated our independence, so they should not be included as a high conflict. (CHRISTIANSON1_27-2)

Comment: A reassessment and clarification on what accounting or bookkeeping services are in conflict and at what level should be taken under consideration. Several accounting, engineering, and verification firms in our industry have gone so far as to develop proprietary software solutions to assist clients with accounting and/or regulatory requirements. We do not see how this creates a high conflict of interest since these services are provided by different departments within the firm, and in most cases, only the licensee has regular access to their individual systems/databases. Finally, given their in-depth understanding of the regulations, most accounting and engineering firms provide information, updates and/or consultative services to regulated parties. We turn to them for expert advice when dealing with constantly changing regulations. If the firm already knows precisely how things are to be done, it simply makes sense to be able to talk to them about how to maintain strict adherence to the program. Again, this need is usually served by a different department or team within the firm. Murex is ready to move forward with our plants on scoring, modeling, and establishing the new pathways but we do not wish to eliminate any of our already limited options due to the potential for conflicts of interest. Any additional guidance in these areas would be greatly appreciated. (MUREX1_60-4)

Comment: Below are some specific examples of how the conflict of interest requirements may be too restrictive:

§ 95503(b)(2)(A)

- This provision prohibits verification bodies from providing “data management system for data submitted pursuant to this subarticle or MRR.” EcoEngineers offers a RIN tracking system to the biofuels industry that allows data transmittals from biofuel plants to the EPA for RIN generation purposes. The system acts as a virtual mail service that transfers data from one party to another and stores it for future retrieval for record-keeping and auditing purposes. We do not believe this creates a high conflict scenario and it provides our auditors up-to-date information on fuel transaction and credit generation at the facility. However, the broad language in the proposed regulation creates the potential for a high degree of conflict and may prevent us from using this valuable tool to enhance our verification services.

§ 95503{b)(2)(H)

- This provision triggers a high conflict if a verification body provides “verification services that are not conducted in accordance with, or equivalent to, section 95503 requirements.” The EPA's QAP program is currently the most common verification program among U.S. biofuel producers and it is unlikely to be in accordance with section 95503 requirements. We recommend that CARB modify the language in this section to allow current QAP providers to perform LCFS verification activities without triggering any conflict of interest.

§ 95503(b)(2)(L) and §95503(b)(2)(C)

- § 95503(b)(2)(L) triggers a high conflict if a verification body provides “appraisal services of carbon or greenhouse gas liabilities or asset,” and §95503(b)(2)(C) triggers a high conflict if a verification body provides “consultative engineering” services. EcoEngineers sometimes provides its clients the current market value of renewable fuel credits as seen in 3rd-party market transactions or other publicly available data such as CARB’s website. This data may or may not be part of an independent economic analysis that compares potential revenues from credits with estimated capital and operating costs at a facility. It is our unbiased, independent opinion of the value of the credits that creates value for our clients. We do not believe these services trigger a high conflict, and there should be some allowance for these types of relationships to continue; however, the proposed rules create significant ambiguity and may prevent us from providing validation services for some clients. (ECOENGINEERS1_B5-4b)

Comment: We remain concerned about the cost of verification to LCFS regulated entities and the general lack of qualified verification providers in the market today, given the strict conflict of interest provisions outlined in the proposed amendments. As of today, there are only two primary RFS QAP providers for the entire RFS program and both of these QAP providers are already verifying fuel pathway activities for numerous LCFS regulated parties. The strict conflict of interest provisions will likely prevent these QAP providers from also providing LCFS verification services due to the fact that their services regularly reach beyond QAP verification into industry expert consulting. Not only does this limit the existing pool of qualified verifiers but it also subjects LCFS regulated entities who already participate in the QAP program to substantial additional verification costs. (CE1_92-13a)

Comment: However, we do have several concerns with respect to the verification program; namely, the conflict of interest provisions that have been layered into the amendments, and also the pool-qualified verifiers that will be available. Echoing some of the other concerns that have been brought forward, we want producers to have stability in LCFS, and that includes verification costs.

So we just want staff to take a long, hard look at the proposed conflict of interest requirements that have been put into the amendments. We have proposed in our written comments to align the verification program with the RFS QAP program, because we

believe that there will be considerable overlap between these two verification programs. (CE2_T5-3)

Comment: Additionally, the description of services provided in Section 95503(b)(2)(U) is overly broad and may inadvertently eliminate a number of qualified verification bodies. We propose that the language be modified to read as follows (additions or deletions relative to the provision as currently written in the Proposed Regulation are marked in underlined or strikethrough text, as applicable):

> "Expert services to the entity required to contract for verification services~~, a trade or membership group to which the entity required to contract for verification services belongs,~~ or a legal representative, in either case for the purpose of advocating the entity required to contract for verification services interests in litigation or in a regulatory or administrative proceeding or investigation." (EMRE1_B16-1c)

Comment: In particular, Section 95503(b)(2)(U) should be removed in its entirety. This provision states that if a verifier has contracted for certain activities with a Trade Association, of which the verified facility is a member, then the verifier is subject to COI provisions and likely disqualification from the engagement. This provision is entirely unnecessary and is ill advised. (RPMG1_64-17)

Comment: However, DTEBE believes that the conflict of interest provisions may be too broad and result in difficulty obtaining verification services for large companies like DTE.

In 95503, CARB outlines a variety of conditions that would constitute a high level of conflict of interest for potential third-party verification providers. 95503 (b)(2)(U) states:

> "Expert services to the entity required to contract for verification services, a trade or membership group to which the entity required for verification services belongs, or a legal representative for the purpose of advocating the entity required to contract for verification services interests in litigation or in a regulatory or administrative proceeding or investigation."

DTEBE believes this provision is too broad and does not accurately reflect high-level conflict of interests for fuel producers. The structure of this provision suggests that any firm who has provided expert services for a project owner in the past is now unable to act as a verification body for the LCFS program. For an entity such as DTEBE, with a long history in the biofuels industry and a broad portfolio of RNG projects, this may limit the potential number of verifiers that can be utilized for the LCFS program. Furthermore, DTEBE is part of a Fortune 500 company, DTE Energy, which contracts for a variety of expert services from a variety of firms. DTE Energy also has memberships in various trade and industry groups, both in the RNG space and unrelated to its RNG activity, that could each represent a conflict of interest under this rule language. The Renewable Fuels Standard Quality Assurance Protocol (QAP) program, which has a similar structure to the proposed LCFS verification program, has only three approved Q-RIN verifiers. This low number severely limits a project

operator's choice of Q-RIN verifiers and stifles competition for these services. We are concerned that language in this conflict-of-interest provision could lower viable options for LCFS verifiers to a similar level, especially for large firms such as DTEBE. Eliminating this provision in whole or in part, or narrowing its scope to more accurately reflect the expert services and trade/membership group relationships that reflect a conflict of interest, would help ensure that DTEBE has an adequate supply of firms available to provide high-quality verification services. We propose the adopting some form of the following amended language below:

"Expert services to the entity required to contract for verification services solely with respect to a specific project or a legal representative for the purpose of advocating the entity required to contract for verification services interests in litigation or in a regulatory or administrative proceeding or investigation." (DTEBE1_56-6)

Comment: We have had discussions with companies that have shown interest in acquiring services to assist in preparing them for LCFS verification implementation. We would like to offer these clients some assistance, but also do not want to trigger a high risk of conflict of interest in doing so. The idea is to complete many of the verification data checks on 2019 data and to draft a mock corrections log and report to give the client an idea of where they may have issues. This would allow them to make corrections or changes to their processes and documentation prior to the actual implementation period.

Our firm would provide the client with the errors that we would be logging and reporting if the verification regulation was effective, but we would not be advising or consulting on corrective action plans. The corrections log maintained during this interim period would not be accessible to CARB. This would allow the entity to identify errors prior to the LCFS reporting period, making a smoother and more accurate implementation. It would also allow us as the verification body to test and adjust our verification procedures and start creating documentation and reports in anticipation of the effective date of the rule. We would also anticipate bringing questions to CARB and sending in mock reports so that CARB could see and approve our deliverables prior to implementation. We would not need anything in the regulation to address this service, we would just like confirmation that if we provide this service that we will not be restricted from doing the verification when the rule becomes effective, and also that we are not starting the clock on any rotation rules that may still be in play. (CHRISTIANSON1_27-7)

> **Agency Response:** Staff has worked with commenters to make clarifications and proposed changes to address specific concerns to the high-risk conflict of interest provisions, while safeguarding verifier independence consistent with CARB's other verification programs. Narrower scopes of service are removed from the high conflict list that staff agrees are low risk or can be mitigated for medium potential for conflict of interest.
>
> The narrow category of accounting softwarehas been removed from the prohibition on providing services related to development of information systems (section 95503(b)(2)(G)), as staff agrees with commenters that this can be

mitigated as a medium potential for conflict of interest if it does not meet the low risk criteria. Based on the information provided in this comment, it appears that the RIN data transfer tool may be included in section 95503(b)(2)(G) and not section 95503(b)(2)(A), but staff would need to fully evaluate the services provided through the disclosure process during regulatory implementation.

Staff excluded attestation services and services that will not be part of the verification process from the prohibition in section 95503(b)(2)(N). Staff agreed with the commenter that further clarification of section 95503(b)(2)(N) would be helpful and that attest services should be excluded because they are low risk for potential conflict of interest, since they are performed under independence requirements. Staff made the suggested change to its proposal: "Bookkeeping and other non-attest services related to accounting records or financial statements, excluding services and results of those services that will not be part of the validation or verification process."

The phase-in period, extended to August 31, 2023, would allow staff additional time to evaluate whether narrow scopes of service provided by verification bodies could continue to be sufficiently mitigated. In the 2nd 15-day proposed changes, staff included an additional category for potential conflict of interest—consulting and design services in section 95503(b)(2)(C)—also to be treated as medium risk until August 31, 2023. Staff disagrees that consulting and design services in section 95503(b)(2)(C) should be considered a medium conflict indefinitely, due to the need to avoid verifying one's own work (applies to an individual or firm).

In section 95503(b)(2)(A), staff proposed additional clarifications for services with high risk of potential conflict of interest by specifically excluding third-party engineering reports provided pursuant to U.S. EPA RFS. Staff consider these reports to not be a high risk, since professional engineers are required to provide an objective report and a statement that s/he is an independent third party meeting each requirement at 40 CFR 80.1450(b)(2)(ii).

Staff further modified the proposal to clarify in section 95503(c)(3) that audit services provided under U.S. EPA's RFS program do not pose a potential for conflict of interest and explicitly excluded the following from categories of risk: QAP audits, attest engagement services, and third-party engineering reports. This modification coincides with the proposed change in section 95503(b)(2)(A) as discussed above. In addition, staff clarified in 15-day changes that verifications conducted pursuant to MRR or the Cap-and-Trade Regulation do not pose a potential for conflict of interest, because these services are conducted under independence requirements that are similarly rigorous to those proposed under the LCFS verification program. Therefore, no change was made to section 95503(b)(2)(H) regarding QAP audits.

Staff considers independent, third-party opinions of credit values based on public data or project costs and revenues for *future* projects to be included in section 95503(b)(2)(C). Verifiers would be prohibited from advising clients on credit

values for currently banked credits under section 95503(b)(2)(M). Section 95503(b)(2)(L) applies to appraisal of existing carbon or greenhouse gas liabilities and assets and has not been modified, because this could result in verifying one's own work. As we understand it, none of the audit firms that provided comments currently perform appraisal services.

Verification bodies would not be permitted to provide LCFS compliance advice, including regarding flow meter locations. Instead of 95503(b)(2)(C), this type of advising would be categorized under section 95503(b)(2)(A): designing a data management system for LCFS data. In this scenario, the verifier should advise the client to discuss metering compliance with CARB staff. CARB staff will provide compliance assistance to the regulated entity and include communication with the verifier, as appropriate. Instead of giving compliance advice, verifiers would describe a nonconformance with monitoring requirements and cite the section of the regulation in an issues log included in the verification report.

Staff's proposal does not permit expert services (under section 95503(B)(2)(U)) that would advocate for the client's interest in litigation or in a regulatory or administrative proceeding or investigation as it would compromise verifier impartiality.

Staff agrees with the commenter that LCFS readiness audits could be helpful for regulated entities; however, regulated entities would need to hire a different firm to provide LCFS readiness audits, instead of the firm they plan to utilize for LCFS verification services. LCFS readiness audits, regardless of the data year reviewed, would be included in the high conflict of interest prohibitions in sections 95503(b)(2)(D) and 95503(b)(2)(Q). CARB accreditations to conduct LCFS verification services would not be expected to be completed until the latter half of 2019 and CARB's verification oversight program would not be in place until 2020; therefore, LCFS audits conducted before 2020 would be considered internal audits. While independent LCFS verification services would not be permitted in 2019, staff added clarifications to section 95501 regarding how quarterly 2020 data review may proceed in the context of annual LCFS verification services, such that issues found and documented in the issues log can be corrected early by LCFS participants. Please see response O-4 regarding quarterly verifier review.

Please see Response O-2.1 in this chapter regarding sufficient number of qualified verifiers and verification cost.

O-2.4. *Miscellaneous Conflict of Interest*

Comment: Under the Section 95503(d) of the draft regulation order, ARB should add more stringent requirements on medium conflicts of interest. Firms that provide verification Services should list all of the conflicting Services they offer on the lcfs website. Furthermore, the requirements for medium conflict of interest should be specified. For example, individuals working on providing advice to fuel producers

should not work for the same supervisor as individuals doing verification services. (LCA2_66-1)

> **Agency Response:** Staff does not publish the particular services provided to particular clients disclosed by verification bodies in their conflict of interest self-assessments. Typically, firms will list the range of services they offer on their own websites.
>
> Staff disagrees that additional requirements for medium conflict of interest should be specified. Staff is maintaining consistency of the proposed conflict of interest disclosure and mitigation requirements with CARB's other verification programs. Services that would be assessed as medium potential for conflict of interest require case-by-case review by CARB to evaluate whether the verification body's proposed mitigation is sufficient. Based on staff experience, the minimum regulatory requirement to demonstrate "any individuals with potential conflicts have been removed and insulated from the project" is sufficient and may include first-line supervisors. Staff's proposal maintains flexibility for verification bodies to assess and manage the medium potential for conflict of interest.

O-3. Multiple Comments: ***International Certification Systems – Allow Use of Existing Certification Schemes, Government Authority Maintained, Cost and Oversight Concerns***

Comment: Enerkem recommends allowing certification systems approved for the European Renewable Energy Directive (EU RED) to provide LCFS verification services for the California LCFS, in order to help ensure a smooth transition when the amended LCFS is implemented in 2019. (ENERKEM1_135-7)

Comment: While registering as an ICC feedstock supplier is an option and we support ISCC as a system to be incorporated into the LCFS program, the current marketplace requires more flexibility for suppliers not currently in that program. (REG1_88-3c)

Comment: However, the full details of the current staff proposal do not take proper advantage of existing experience from other jurisdictions and established certification schemes. Many of these schemes work efficiently, have adequate technical competencies already established, work globally, and can react quickly to market changes. Regulating authorities can efficiently control certification schemes. Utilizing existing certification schemes would not remove the ARB's control and would not give away its responsibilities.

Many producers who participate in other markets already participate in one or more other verification system. Implementation of an additional, California-specific system is inefficient and will lead to significant additional costs for producers as verification/certification for different markets will require multiple, overlapping audits. <u>To the greatest extent possible, Neste recommends that California fuel reporting entities be allowed to utilize existing certification schemes that can accomplish the LCFS verification requirements.</u> (NESTE1_76-9b)

Comment: We would caution that some of the things that had been proposed seem to be a bit restrictive and a bit specific to California. One of the things that's important is, as California as a leader, looking to hopefully export this program into other people as they try to “me too” and follow on, trying to make that program where it's more able to work for other jurisdictions that don't have the kind of dedicated staff expertise and staff efforts.

One of the ways that you can accomplish that, by looking at existing verification schemes that are out there, that are international, that can accomplish the same and similar goals that this program is looking for, that have been functioned in many of the other kind of global programs that are like that, allowing those to come in and take part in the system; instead of it just making a California-specific sort of auditor, will both increase efficiencies as well as transparencies among the auditors, the obligated parties, so they've got systems in place that are routine, they're predictable but they understand that -- and then are not duplicative of each other. (NESTE2_T11-3)

Comment: This comment relates to the proposal for verification related to the recordkeeping and traceability requirements for waste and residue feedstocks. Under the proposal by CARB certification systems that already provide such verification services under the EU RED will not be recognized. This has cost implications for supply chains and for CARB, especially for international supply chains, that use these systems and wish to supply the California market. For supply chains that use EU approved certification systems they will incur duplicate costs to provide the same information to CARB as they provide to the EU. For CARB it will now need to incur substantial costs to duplicate the verification infrastructure that the certification organizations offer globally. One certification organization, ISCC, is active over 90 countries and conducts training and oversight in the US, Canada, Europe, China, South Asia and South America to ensure the low carbon fuel requirements are verified for the EU. CARB will need to provide an equivalent communication, education, training and oversight service to these supply chains inside and outside the US. As a Canadian working with the canola industry that supplies renewable fuel to the California market I anticipate attending a CARB workshop in Canada once the regulation takes effect. (DR1_40-1)

Comment: The amendment does not consider the existence of already well established certification schemes. The use of multi stakeholder certification schemes can be considered as best practice. Such schemes work efficient, have technical competencies, work globally, are not restricted by public sector constraints, and can re-act quickly to market changes (ISCC1_22-1, UIC1_25-2)

Comment: The approach chosen by ARB will lead to tremendous additional costs for companies as verification / certification for different markets will require multiple audits. (ISCC1_22-2, UIC1_25-1)

Comment:

- It is extremely important to control global supply chains, particularly for low carbon feedstock. It is unclear how this will be implemented.

- Government authorities can efficiently control certification schemes. Using certification schemes would not mean that Government authorities give away responsibilities of public authorities. (ISCC1_22-4)

Comment: I believe that existing certification systems should be considered as companies have invested heavily in setting up the administrative infrastructure and compliance measures. Though such systems may need to be modified to suit the LCFS, it will not be nearly as expensive as an additional certification system. As the overriding objective is to promote the use of the LCF, the avoidance of incremental costs will go a long way to help the industry be as competitive as possible. (RV1_24-1)

Agency Response: Staff has been in discussions with the larger multi-stakeholder certification systems (ISCC, Bonsucro, and Roundtable for Sustainable Biomaterials). Staff acknowledges the technical competency and global presence of these international certification systems and continues to explore how staff may work together to support the objectives of the LCFS. For purposes of this amendment, staff is focusing on developing a verification program that ensures all verification bodies are accredited by CARB, subject to the same oversight, meet the same requirements, and have access to the same training and guidance. The proposed verification program ensures that the requirements in the LCFS regulation, including accreditation and verification, are implemented and interpreted consistently for all entities participating in LCFS. We expect certification bodies performing biofuel audits for select international certification schemes to apply for accreditation as LCFS verification bodies, and their individual auditors would be eligible for fast-track accreditation.

Staff understands that close government oversight can be an effective program design element that some jurisdictions have included when recognizing biofuel certification schemes. However staff's regulatory proposal focuses on direct oversight by CARB of regulated entities, verification bodies, and individual verifiers without explicitly recognizing international biofuel certification systems.

Staff's proposal does not explicitly recognize ISCC certification as a substitute for LCFS compliance demonstration. Staff's proposal provides flexibility that allows feedstock suppliers that want to be recognized for lower CI operations to meet LCFS requirements by becoming a joint fuel pathway applicant, without becoming registered as an ISCC feedstock supplier. However, staff anticipates that most of the recordkeeping practices that support maintenance of ISCC certification will also support LCFS compliance and vice versa. Staff's proposal relies on the verifier's professional judgement of risk in developing a plan for sampling chain-of-custody information for specified source feedstock to the point of origin. This approach provides reasonable assurance while not relying on strict chain-of-custody and management system certification along the supply chain as required by ISCC and implemented in the EU RED, and allows staff to continue to evaluate the risk of mischaracterizing low CI feedstocks in the LCFS program. Please also see Response O-9 in this chapter regarding verification of specified source feedstocks.

The cost for a pool of potential verifiers will be reduced as CARB considers auditing firms contracted to conduct audits in cooperation with select international certification systems to have the comprehensive general GHG verification experience needed to pursue CARB accreditation under the LCFS-specific training option rather than needing to undergo the comprehensive general verification training and examination program. This is an option that will fast-track international verifiers and help fuel producers inside and outside the U.S. obtain CARB-accredited LCFS verifiers. The intent is to incorporate a way for producers who are undergoing certification for the EU and other markets to also be audited for the LCFS at the same time. CARB staff anticipates that LCFS verification would occur at the same time as EU RED audits for efficiency as the auditors seek and maintain accreditation to conduct LCFS verification services.

CARB will consider developing guidance in areas of specified fuel feedstock for reporting entities that have achieved international certification (i.e., ISCC, RSB, Bonsucro) and implement recordkeeping that is deemed adequate.

CARB is working with other jurisdictions who have implemented similar low carbon fuels programs and understands the desire/need to establish protocols that can be exported. Future linkage possibilities with other jurisdictions would require a full regulation amendment.

O-4. Multiple Comments: *CI Pathway Maintenance and Verification – Verification Frequency, Variability of Carbon Intensity, Enforcement for Normal Fluctuating Operations*

Comment: …but the annual CI verification requirement is disproportionate given the fact that a pathway applicant must supply two years of operating data in order to obtain a certified CI. The verification requirement should fall within the same parameters as pathway certification in order to maintain consistency in the program. Specifically, the pathway verification should occur every two years, rather than annually. Disconnecting the verification period from the period used to establish the certified CI value can lead to false determinations that the facility is operating significantly differently than the certified pathway basis. An annual CI verification provision assumes that one year of operating data is reflective of “normal” operating conditions at a facility. Unfortunately, this may not always be the case as production facilities can experience unexpected variability in operating conditions causing deviations from a certified pathway. Production facilities experience periods of planned or unplanned maintenance and upgrades that can affect the annual CI score, but are otherwise captured in the two-year data used to certify the pathway.

The annual CI verification will have the most significant impact on dairy digester projects. The CI of dairy digester projects face a degree of variability over the course of an annual reporting period that is outside the control of the individual dairy digester

producer. A variety of factors can cause fluctuations in CI, including temperature, weather patterns, the efficiency of gas collection, and the number and ratio of dairy to non-dairy cows on a farm. These fluctuations can cause operational CI's for dairy digester projects to vary significantly from their certified CI's. Given the significant variability of dairy digester operating conditions, Clean Energy recommends that Staff reconsider the annual CI verification requirement and instead adopt a biannual CI validation requirement that mandates all fuel pathway holders to obtain a new CI every two years based on the latest two years of operating data.

Pushing the CI verification out to two years eliminates the risk of modeling "atypical" operating conditions while effectively creating a rolling CI re-certification process that ensures that each pathway CI reflects the most recent two years of operating data. This two-year window of CI verification will also likely sync up with the timing of future GREET Model releases, which will also require pathway CI scores to be updated. (CE1_92-7)

Comment: Furthermore, Section 95488.10(a)(7) of the amendments indicates that non-compliance with a certified CI represents non-compliance with the LCFS regulation and subjects the fuel producer to possible enforcement action. However, we must emphasize that subjecting producers to enforcement action for fluctuating operating conditions is excessively punitive towards an opt-in producer of a low carbon fuel that is helping California achieve its greenhouse gas reduction goals.

The proposed verification program will ensure the correct number of credits are generated, especially given the fact that producers will have to surrender credits if their operational CI exceeds their certified CI. Given the known fluctuation of operating conditions of biofuel projects, especially dairy digester projects, these particular provisions of the amendments regarding enforcement seem harmful to the program's overarching goal and will not promote further fuel pathway CI reductions. Clean Energy recommends that Staff remove both provisions mentioned from Sections 95488.4 and 95488.10(a)(7) and instead the two-year ongoing CI verification requirement referenced above. (CE1_92-9)

Comment: The verification requirements, as outlined in the proposal, are very extensive and will be burdensome to regulated entities. There will also be an administrative burden for ARB due to the very large number of verifications, and the potential for needed actions because of the verifications (CI variances that affect credit balances, volume differences, etc.). We ask that ARB look at options to reduce these burdens by reducing the required verification frequency. This could be based on positive outcomes of the initial verifications. For example, a regulated entity that had an initial positive verification would be allowed to move to a less stringent schedule (e.g. every other year). Another example might be to allow combining the U.S. EPA required facility engineering reviews with the LCFS verification so that one verification body could complete both, and data gathered could be applied for both requirements (the EPA required this review every 3 years). (P661_55-6)

Comment: We recommend that the current regulation allow an optional quarterly verification to be completed by the verification bodies. The sample selections for each quarter would be proportionate to renewable fuel output depending on the production

cycles of the reporting entity. Additionally, a sampling plan would be created by the verification body and available upon CARB's request prior to the commencement of the quarterly verification. This option would allow the verification body an even distribution of verification work throughout the year instead of condensing it after year-end. All findings would still be reported in a corrections log that would be available to CARB.

In addition, the quarterly verification would allow for the identification of issues at an earlier date, rather than waiting 6-8 months after the reporting year before identifying problems. We do not have the intention of this being a mandatory quarterly verification, but rather an option of completing this work on a quarterly basis. (CHRISTIANSON1_27-5)

Comment: Regarding verification services, we would like to be able to have our auditor start reviewing documents as soon as is feasible. We are not sure how possible that is if a notice has to be submitted to ARB every year prior to conducting the audit. For example, under a RFS attest for 2017, REG has the attest start sometime in Q2 2017 to help spread out the testing throughout the year and into early 2018 so that the audit is done by the end of May. This benefits both REG by having quicker feedback to correct issues sooner and our auditors so they can spread the work out more evenly throughout the year.

Regarding site visits, REG thinks an initial site visit is appropriate, but the next site visit shouldn't be for another 2-3 years unless the risk from the production facility or an FPC goes up. Generally, there is no need to keep visiting the site unless a material change has occurred especially since the RFS engineering reviews do a site visit every 3 years. (REG1_88-29)

Comment: Another competitive advantage afforded to EV fuel applications is the lack of an annual CI verification requirement. Under the verification proposal, a fuel pathway holder must verify that their actual operating CI is equal to or less than the certified CI that is used to generate credits. EV fuel applications are able to generate credits using the California grid mix lookup pathway. All other producers of biofuels must apply for their own specific fuel pathway and be subject to annual CI verification. Invalidation risk is a strong concern for low carbon producers and certified pathway holders. However, that EV credits generators are immune to this risk based on the system that Staff has developed.

More specifically, LCFS credits are generated quarterly yet CI verification occurs annually after credits have been generated and possibly monetized. This means that producers will be generating credits before having the operational data necessary to corroborate the certified CI for the given year. This puts the credits generated during the period (up to four quarters worth of credits) at risk of invalidation if the operational CI is higher than the certified CI. As a result, credit generators will hold perpetual invalidation risk which will have significant negative impacts on the LCFS credit market. EV credit generators on the other hand have zero invalidation risk since use of a lookup value pathway does not require annual CI verification. This allows EV credits generators to generate and monetize credits uninhibited while bearing no additional cost for CI verification. It also allows EV credit generators to take full advantage of the credits they generate without having to contribute a single allowance to the proposed buffering account. This is clearly a competitive

advantage to EV fuel applications as all other biofuel pathways are subject to costly (and artificial) invalidation risk in addition to unknown but inevitably significant verification costs.

The rationale that all EVs use electricity is not sufficient justification for this change. An EV can use grid power, all renewable power or a mix, with wide ranges in the overall carbon intensity. Verification of EV fuel use (power generation mix) is just as important for program accuracy as verification of gas type for a natural gas vehicle. There is simply no valid reason why verification requirements should be different for different fuel or vehicle types, particularly when both EV's and NGV's can provide a wide range of greenhouse gas reductions (CI's). (SCG1_75-7)

Comment: ARB proposes to incorporate provisions requiring third-party verification of nearly all aspects of reporting within LCFS. Kern is wary of the increased burden this will impose on fuel reporting entities, especially those with multiple reporting obligations within the various program elements. ARB's proposal applies verification requirements much more broadly to fuel reporting and project reporting, whereas workshops and concept papers to date have presented a verification scope primarily limited to that of fuel pathways.

Kern recognized that ARB is incorporating concepts aligned with verification requirements existing in the Mandatory Reporting Regulation (MRR) and compliance offset protocols in the Cap and Trade program. Further, Kern acknowledges that ARB's proposal includes a provision that allows a reporting entity to amend the written monitoring plan in place for MRR reporting to include the requirements for LCFS verification. Nonetheless, Kern is concerned about the overlap and duplicity of reporting and verification requirements. Reporting and verification must be simple, efficient and avoid unnecessary implementation costs for regulated parties. Kern urges ARB to review the entirety of provisions for report verification for areas of overlap, and to simplify the breadth of data that LCFS verification bodies must review.

Kern is cautiously optimistic that ARB is incorporating verification provisions in consideration of each certified pathway's unique attributes. Specifically, ARB's proposal specifies a verifier must develop its own validation/verification plan specific to the client and data available, consider incorporating easily obtained, accurate, measurable, and verifiable data to be included as part of the plan, and specify which parameters require ongoing data as opposed to other inputs that have little variability. Kern urges ARB to continue working with stakeholders and prospective verifiers on the best way to implement these concepts on a practical level. Pathway holders should be afforded the opportunity to work with ARB on training and certification materials for approved verifiers, and with the verification bodies in determining the final parameters of the verification plans, required parameters for data checks, and similar components key to the verification process. (KERN1_115-2)

Comment: In § 95500(b)(2)(A), the section states that verification will be done annually. WSPA recommends ARB looks at providing options to reduce the burden. Holders of site-specific certified fuel pathways are also subject to USEPA regulations under the Renewable Fuels Standard, which requires a third-party engineering review ever 3 years. One option to reduce the LCFS verification administrative burden would

be to allow these facilities to be on the same triennial schedule, and utilize the data and outcome of the USEPA verification in the LCFS verification process. Another option might be to allow a less frequent verification requirement for facilities that receive a positive verification statement in their initial verification. (WSPA2_61-25)

Agency Response: Staff has not changed its proposal regarding fuel pathway reporting and verification frequency and site visit frequency due to overriding considerations of program integrity and practical administration. Annual reporting and verification of operational carbon intensity data are necessary for CARB to timely review pathway certification conformance and obtain assurance that reported carbon intensity data are accurate. Annual error corrections and credit adjustments are necessary for practical administration and to avoid larger and less frequent corrections in the LCFS credit market. This is because credits generated for alternative fuels are issued after validation, but prior to final verification of historical data. Review less frequently than annually would not be practical or advisable, except for smaller projects.

Note that while annual fuel pathway review is required, operational CI is based on rolling two-year operational data to smooth out normal operational fluctuations and be consistent with calculation of the initial certified CI. This two-year rolling average should be sufficient for dairy digester projects as well. Fuel pathway holders have the option to include a margin of safety in the certified CI to manage risk of noncompliance and credit adjustments. In cases where less than 24 months of operational data are available, a provisional CI would be issued by CARB which recognizes, for purposes of enforcement, that variability of operations is not expected to be included in smaller sets of operational data. CARB retains discretion to determine whether credit adjustments should be made based on the specific facts.

As stated in the ISOR, annual site visits are reasonably necessary for confirmation of facility operations, review of substantiating documents for site-specific CI inputs, interviews with key personnel, and direct sampling of data from data management systems and accounting systems. Site visits are necessary to ensure all sources and processes are included in the emissions estimates and to check the data report for completeness. Please see Response O-8 in this chapter regarding harmonizing with U.S. EPA RFS requirements and expected efficiencies of conducting RFS and LCFS audits, including third-party engineering reviews, at the same time.

In addition, the regulation includes an option to defer third-party verification of annual Fuel Pathway Reports and Quarterly Fuel Transactions Reports meeting specified criteria, due to the low risk to the LCFS credit market and to manage costs associated with verification for smaller projects.

Under the proposal for project-based crediting, staff has provided flexibility for reporting and verification frequency that allows project operators to manage the costs versus benefits of their projects given the number of credits to be issued

and the cost associated with verification. This flexibility is possible, because credits are not issued until verification is complete.

Staff agrees with commenters that quarterly verification review should be allowed, and made changes in section 95501. These changes address stakeholder comments by providing flexibility for verifiers to review reported data and identify any issues prior to annual reporting and final verification. In addition, these quarterly review provisions provide requirements for verification planning and documentation that must be generated and maintained by verification bodies.

Staff disagrees that EV credit generators have an unfair advantage based on staff's fuel pathway requirements. Staff's fuel pathway requirements are based on practical considerations for program administration and simplified methods are supported by conservative assumptions. Lookup table fuel pathways do not require annual fuel pathway reporting or third-party validation or verification because they do not rely on site-specific CI data.

As stated in the ISOR,

> Lookup Table pathways generally have well-defined life cycle carbon emissions with conservative inputs, posing a low risk of under-counting pathway GHG emissions. Additional records are necessary to ensure that electricity reported under a low-CI electricity pathway for electric vehicle charging and electrolytic hydrogen production is utilizing qualifying low-CI resources under an approved arrangement. …
>
> CARB staff does not consider third-party verification necessary at this time for electricity and hydrogen (excluding pipeline biomethane used for SMR). Since electricity and hydrogen for vehicle fueling are expected to primarily be credited through Lookup Table pathways, based on metered data, staff expect data assurance needs will continue to be within the staffing capacity of CARB to conduct periodic compliance audits.

Staff has worked with LCFS participants to review the Tier 1 Simplified CI Calculators to ensure fuel pathway application and reporting requirements balance the need for accurate site-specific data (to incentivize continual improvement in reducing CI) with the use of default values (to simplify monitoring, reporting, and verification). As specified in section 95488.7 of the regulation, to apply for a Tier 2 pathway will become an iterative process where the applicant recommends data that is site specific then CARB staff review for consideration of a pathway CI.

Similar to the MRR verification process that California petroleum refineries undergo, the LCFS verification process will include fuel pathway holders presenting their monitoring plan and other relevant information to the verifier to expedite the onboarding process. Staff will continue to reach out to LCFS

participants to identify areas where case-by-case guidance may be helpful or where publishing more generally applicable guidance may be helpful. Verifiers will be expected to follow the regulation and written guidance by CARB, requesting interpretation of the regulation if a real scenario does not appear to be clear. CARB's verifier training and oversight program will include review of the regulation as well as published guidance, as it is developed.

O-5. Multiple Comments: *Consider Trial Period to Assess Unforeseen Implementation Impacts, Verification Costs, Market Uncertainty and Credit Invalidation*

Comment: However, the proposed ongoing Carbon-Intensity (CI) recalculation and verification of existing fuels produced and delivered from operational facilities has the potential to add substantial cost and foster perpetual uncertainty around the LCFS credit market, including but not limited to LCFS credits generated by RNG. (RNGC1_16-4)

Comment: The RNG Coalition asks that you consider implementing the proposed third-party verification requirement on a trial basis with a commitment to re-visit the parameters and review stakeholder input after some predetermined period of time in order to develop an optimal third-party verification system. During this trial period, credits would not be invalidated due to unforeseen impacts associated with the implementation of third-party verification. (RNGC1_16-6)

Comment: A primary objective of the proposed LCFS amendments is to require a new independent third-party verification program. While it is reasonable for CARB to want assurances regarding the accuracy of data reported under the LCFS and to streamline the use of staff resources, we are concerned the costs and burdens associated with the new verification program (likely underestimated by CARB's expectation of $4 million by 2030) outweigh perceived benefits. We encourage CARB to give special consideration to comments from Christianson PLLP, a firm with extensive experience in auditing and verification services. As an alternative to mandatory third-party verification, we suggest making the program voluntary for a trial basis and capitalizing on the experiential learning to develop a more reasonable common sense approach.

We are concerned the proposed mandatory verification system creates significant additional costs, market barriers, and regulatory risk to fuel providers while it removes incentives to innovate or benefit from process efficiency gains. We urge CARB to consider ways to minimize or contain verification costs. Just as LCFS cost containment solutions have been enacted to protect consumers and market participants, so too should cost containment solutions be provided for verification costs. Our pathway-holding members will examine these costs very closely when determining whether or not to participate in the LCFS in the future. CARB should take additional time to weigh the benefits and costs of the proposal and take into consideration unintended consequences of discouraging program participation. (ACE1_41-4a)

Comment: RPMG supports the addition of verified CI reductions under § 95488.10(a)(6) but requests it be revised to allow producers to generate credits for the period in which their

operational CI has been verified to be lower than their certified CI. This section allows a pathway holder to replace their certified CI with the verified operational CI based on the most recent 24 months of operational data. Under the proposed regulations, producers only generate credits for their verified CI reductions to the extent of their certified CI**. The proposed regulations increase the cost to producers for verifying data but do not reward the producer when their verified operational CI is below their certified CI for the verified period.** This revision would encourage the ethanol industry to do what it has done to help get the LCFS program where it is today, grind day in and out and continue to innovate. (RPMG1_64-12)

Comment: Every consideration for minimizing or limiting the extent of verification costs should be employed by CARB, this letter highlights and suggests some of those opportunities. Though CARB considers them to be “best practices” for a robust GHG reduction program, mandatory verification costs are not nominal or inconsequential for stakeholders. Individual fuel producers and suppliers will examine these costs very closely when determining whether or not to participate in California's program.

Limitations to verification costs should be considered by CARB, including a suspension of mandated verification where aggregate program costs supersede attributable market economics. Just as LCFS cost containment solutions have been enacted to protect consumers and market participants, so too should cost containment solutions be provided for verification costs. (RPMG1_64-13)

Comment: But also that there are costs associated with monitoring and verification. There's costs associated with the new CI requirements and rules. And that the balance between innovation and costs needs to be kept.

There's a lot of small incremental benefits that have been gained quarter over quarter, and the CIs have gone down and down and down. Those fund the bigger jumps in CI that you guys are really looking for. So I just want to highlight that small incremental benefits shouldn't be lost. They should be rewarded so that the larger benefits can come later. (RPMG2_T24-2)

Comment: § 95488.6. (b)(2)

- We support CARB's efforts to implement a robust verification program for fuel pathways. However, requiring that an initial validation be completed before an application can be reviewed and certified by CARB could delay the generation of credits.
- We recommend that CARB allow validation to be completed before or after the application has been reviewed and certified by CARB staff. LCFS credits generated post certification but prior to validation can be locked and held in the pathway holder's LRT account if quarterly reporting must be completed during the validation. This will allow applicants to begin fuel sales into California sooner and prevent potential delays that can be caused by 3rd party validators. (ECOENGINEERS1_B5-7)

Comment: We believe it is important to provide a program that creates a level playing field for market participants. A verified LCFS credit should have equal value regardless of its originating facility. This can only happen if CARB offers a guarantee of authenticity for all verified LCFS credits. LCFS credits function as the currency for trading emissions reductions, and there cannot be any doubt in the marketplace of the validity of the currency. CARB, being the regulatory body issuing the currency, should stand behind it as a guarantor. The mandatory verification program developed, implemented and monitored by CARB should provide CARB the confidence to guarantee the validity of the credits.

The absence of such a guarantee will lead to buyers of credits giving preferential treatment to established counterparties with larger balance sheets to mitigate any potential invalidity in the credit generation or verification process or it will lead to buyers implementing their own verification systems over and above the mandated one. Both of these consequences will defeat one of the main purposes of a mandated verification system: to create market confidence, liquidity, and a level playing field for all fuel pathways.

Downstream market participants should not have the responsibility of further authenticating a verified credit, and they should not suffer consequences of any verified credit they purchase being found invalid at a future date due to no fault of theirs. This does not mean that downstream buyers and regulated entities will have the license to practice reckless behavior and ignore obvious misrepresentations by suppliers. CARB should explore ways to balance a credit guarantee with other controls, so the market bears the cost of credit invalidation. (ECOENGINEERS1_B5-12)

Comment: There is widespread concern over the potential for invalid credits and, given the limited ability of a downstream buyer to protect against a “buyer beware” policy regarding such credits, these requirements will provide some protection. There should be a more explicit release of downstream buyers from liability or penalties as part of the program. With a robust verification program, it is difficult to see what further due diligence a fuel or credit buyer can do to ensure that credits are valid. (CHEVRON1_112-27b)

Comment: IV. <u>Amend the third-party verification requirements</u>. We support CARB’s proposal to improve the quality and accuracy of the LCFS program by requiring third-party verification. However, recognizing the success of the greenhouse gas Mandatory Reporting Regulation (17CCR§95100), we recommend that CARB require third-party verification starting in data year 2020 and implement credit validation starting in data year 2022. This approach will enable reporters and verifiers to focus on implementing the robust requirements of this complex regulation and support liquidity in the LCFS credit market.

…

4. <u>Amend the third-party verification requirement</u>

We support the requirements in §9549, *Fuel Transactions and Compliance Reporting*, in order to maintain a valid fuel pathway code for use in reporting fuel transactions for credit generation. We agree that third-party verification will assure material accuracy and conformance with the regulation. However, we also recognize that this amendment introduces numerous data collection, recordkeeping, reporting and accuracy requirements for entities that may have varying levels of maturity, particularly when applied to alternative fuels, and are concerned that some of the Tier 1 and 2 fuel pathways applicants may require additional time to ensure that adequate operational and instrument controls are installed and maintained to ensure compliance with the LCFS regulation. We are also concerned that the risks and enforcement consequences for not meeting the standards established in the regulation may serve as a deterrent to entry for some credit generators. An unintended consequence of reduced participation would be a reduction in the number of credits available, which in turn would put pressure on the state's ability to achieve its CI reduction target and annual benchmarks.

In order to balance a need for a robust LCFS program and encourage sufficient market liquidity, we recommend that CARB retain the requirement for third-party verification starting in 2021 for 2020 data and implement *§ 95495. Authority to Suspend, Revoke, or Modify, or Invalidate* starting in 2023 for 2022 data. This will allow both regulated entities and verifiers the time needed to meet the detailed requirements of this complex regulation and ensure sufficient liquidity in the LCFS credit market. (PGE1_120-7)

> **Agency Response:** Staff's proposal to add annual fuel pathway reporting and verification is necessary to help ensure the ongoing integrity of the LCFS credit market through assurance of GHG reduction claims in the LCFS. This additional assurance will support market certainty. For these reasons, staff did not make the suggested change to further delay implementation of mandatory third-party verification or begin with a voluntary program. The mandatory third-party LCFS verification program being proposed would start in 2020, *one year after* the regulation would become effective.
>
> Staff disagree that a trial period is needed to assess unforeseen implementation impacts. Staff currently audit LCFS participants and invalidate credits, so the addition of third-party verification does not change these procedures. In the event of a late or adverse verification statement, CARB may investigate; however, credit invalidation is not automatic but would be based on CARB's review of the facts specific to the situation.
>
> Staff understands that reporting entities will have increased costs associated with the new verification provisions in the LCFS, but believes that the LCFS credit value will exceed verification costs incurred. In addition, allowing deferred verification for certain alternative fuel reporting that generates no more than 6,000 credits and deficits addresses the concern by reducing the costs associated with verification for smaller projects. Deferring verification for smaller projects is also low risk to the LCFS credit market. To the extent third-party validation of fuel pathway applications can expedite certification of fuel pathways, LCFS participants can start realizing the credit value of alternative fuels sooner.

Staff does not share the commenter's concern about delay of credit generation due to the third-party validation requirement, since, in the absence of validation, staff resources would have continued to be a limiting factor in assessing application completeness. In addition, staff's proposal allows fuel pathway holders to reduce their certified CI each year, based on verified operational data, if they choose. Updating the certified CI to benefit from incremental improvements is not permitted under the current regulation, so this amendment would be a benefit. Staff did not make the suggested change to allow alternative fuel producers to generate additional credits for the period in which their operational CI has been verified to be lower than their certified CI. Because alternative fuel credits are issued each quarter after fuel quantifies are reported to CARB, but before annual verification is complete, this would be considered retroactive crediting. Please see Responses H-3 and N-6 in this chapter stating reasons for not allowing retroactive credit generation.

Regulatory risk for first fuel reporting entities can be mitigated. Fuel pathway holders have the option to add a margin of safety to protect against CI compliance risk and potential for credit invalidation. The margin of safety provides fuel pathway holders with a mechanism to account for variability of the fuel pathway input data that they may foresee – to assure that the reported operational carbon intensity complies with the certified carbon intensity value. Staff believes ensuring the data quality used to calculate LCFS credits and deficits is an overriding responsibility, outweighing concerns about potential to discourage some participants who may be unable or unwilling to demonstrate compliance.

Staff disagrees that CARB guarantee of credit authenticity for verified credits is necessary or desirable. Invalidation risk for downstream credit buyers is mitigated by the mandatory verification and buffer account provisions. Please see also Response H-1 in this chapter regarding the buffer account.

O-6. *Verification Miscellaneous*

O-6.1 Multiple Comments: *Miscellaneous*

Comment: Section 95500(d) is unnecessary for in-state oil fields. The crude volume does not affect carbon reductions in any manner (crude volumes appear in both the numerator and denominator of the innovative crude calculations), and for in-state producers showing that the oil is sold to a California refiner should be enough. (GLASSPOINT1_65-10a)

Comment: We continue to believe the verification system is generally well thought out, but that it also has the potential to become overly reliant on third-party entities. While there can be a valid role for qualified, third-party businesses in expanding the reach of government, at a certain point expanding the reach of government can become an abdication of government responsibility. We have observed that governments tend to

underfund enforcement activities like this when third-party systems are in place. This model can be effective, but it also has limitations.

To address this concern, we believe that CARB staff should conduct unannounced spot checks of facilities to administer audits because they can be the only truly objective agency in the process. In general, we are concerned about a lack of oversight and direct involvement in the process by CARB enforcement staff. We have seen similar agencies in similar circumstances defer their proper governmental enforcement functions to third parties, with poor results.

In particular, we are concerned about a lack of oversight of foreign entities, especially those which have a financial incentive to claim that virgin palm oil or palm fatty acid distillate is "used cooking oil." For example, the volume of approved pathways and applications for production of biodiesel from domestically sourced used cooking oil in South Korea exceeds the amount of oil available in that country. This is a red flag that should be investigated by CARB staff directly rather than by the third-party auditors who have been hired by the respective companies.

While it would be inconvenient for CARB staff to conduct in-person audits of these facilities located thousands of miles away, that is precisely the point—many of these facilities are located half a world away and do not have other agencies such as U.S. EPA and the U.S. Internal Revenue Service overseeing their activities, like U.S. biofuel plants. In reality, what these companies are doing on a daily basis is a complete unknown. And unless CARB conducts unannounced spot checks, it will continue to be.

We believe unannounced audits and inspections should be prioritized based on the following factors: (1) distance of production facility from California; (2) total distance travelled by feedstock; (3) complexity of supply chain; (4) use of mass-balancing compliance approach with high carbon feedstocks; (5) production facility reliance on used cooking oil not collected from local sources; and (6) volume of fuel sold into the Low Carbon Fuel Standard program.

We also continue to suggest that CARB require bonding for international fuels like the U.S. EPA does for the federal Renewable Fuel Standard. While U.S. producers face severe legal consequences for participating in fraudulent activities, this is not the case for foreign individuals and entities, which creates a special danger and necessitates that <u>something</u> be at risk if fraud occurs. U.S. EPA has recognized and addressed this fact; CARB should as well. (NBBCABA1_29-11)

Comment: Section 95488.8- *Fuel Pathway Application Requirements Applying to All Classifications* contains a subsection which defines confidential business information for the purposes of the fuel pathway application and carbon intensity determination. However, this language does not extend to the third party verifications required for annual fuel pathway reporting, quarterly fuel transaction reporting, crude oil quarterly and annual volume reporting, project review or low complexity/low energy use refinery reporting. These sections lack provisions ensuring that proprietary data is not taken by a third party and/or preventing the third party verifier from inadvertently providing

confidential information to the state. Release of operational data, process design and technology employed, feedstock procurement, and accounting practices could result in entities losing a competitive advantage. (DGD1_69a-3, VALERO1_69b-6)

> **Agency Response:** Staff did not change section 95500(d) regarding verification of refinery reports of crude volumes from in-state oil fields. Crude volumes reported by refineries, whether from in-state or out-of-state, would be used by staff to independently confirm the eligibility of innovative crude producers to receive project-based credits.
>
> Staff agrees with the commenter that unannounced site inspections by CARB enforcement staff, in addition to the proposed third-party verification program, are necessary to avoid fraud in the LCFS program. CARB will continue to conduct both announced and unannounced site inspections and will include facilities located outside the U.S.
>
> Staff anticipates that the verification body and the reporting entity will establish data confidentiality expectations in their contracts, as it has been successfully implemented under CARB's other verification programs. Most auditing firms have procedures and systems in place to protect client information. As a practical matter for program implementation, verifiers are required to share information with CARB upon request and are subject to CARB oversight, including audits.

O-6.2. Multiple Comments: ***Verifier Competency, Guidance, and Fuel Pathway Report Deadline***

Comment: There are some areas that could use some added clarity. Review and approval of audit plans require very clear guidance from CARB. As was said by potential verifiers in the workshops on this topic, clear guidance will lead to consistent quality while guidelines that are open to interpretation may lead to a "lowest common denominator" approach. Consistent quality is critical in this area to ensure both the health of the program and a level playing field between regulated parties. (CHEVRON1_112-29)

Comment: The Section 95502(c) of the draft regulation order indicates that verifiers should have a strong understanding of the CI calculations this is not necessarily true. Verifier should have an understanding of following audit procedures and make sure that the inputs correspond to the verification sheets. If ARB limits the knowledge and scope of verifiers to verifying that receipts and evidence exists the fuel producers will have a broader pool of potential verifiers. (LCA3_68-1)

Comment: REG suggests an April 30th deadline versus March 31st for submitting the Fuel Pathway Report to align with finalizing annual reports in LRT. (REG1_88-23a)

> **Agency Response:** Staff agrees and appreciates the suggestion to provide clear guidance on audit plans and intends to publish guidance for reporting entities and verifiers when appropriate. Staff will also hold informational webinars when necessary. In addition, CARB will require verifier training prior to

accreditation and conduct oversight audits of verifiers to maintain a level playing field.

Staff agrees that audit skills are a fundamental competency for third-party verification of fuel pathways. However, as stated in the ISOR (p. III-166), staff proposed that accreditation as a lead verifier for validation of fuel pathway applications or verification of Fuel Pathway Reports requires the verifier to have experience in alternative fuel production technology and process engineering. This requirement is included because verification of these components of the LCFS program requires a strong understanding of life cycle analysis for CI, along with an understanding of biofuel production processes, which are often complicated and involve many different feedstocks and chemical processes. This requirement is analogous to the sector-specific requirements in MRR. One example is the need to understand material balances and process flows to verify allocation of multiple fuel pathways to produced fuel.

Staff did not extend the deadline for Annual Fuel Pathway Reports from March 31 to April 30, as it is critical for the verification season to be long enough to conduct rigorous verification services. Verification services cannot begin until the Fuel Pathway report is submitted to CARB. The March 31 deadline must be maintained and the reporting entity must attest to the veracity of the data; however, if errors are found during the verification process, the verifier will note it in the issues log and reports must be corrected before the end of verification services.

O-6.3. Multiple Comments: *Thresholds and Exemptions*

Comment: On the Triennial Verification section, REG recommends 25,000 credits during a calendar as a threshold to mirror MRR versus 6,000. Related to this, the threshold for reporting to LRT could then be 10,000 credits similar to how the reporting requirements for MRR work. (REG1_88-27)

Comment: In the proposed rulemaking set for adoption in 2019 ARB has added for Validation of Fuel Pathway Applications; and Verification of Annual Fuel Pathway Reports under §95500. White Energy supports the Boards commitment to bringing assurance to carbon credit generation and transactions. We feel that greater assurance will provide more stability for the LCFS and the credits it generates. However, the proposed verification regulations may prove to be challenging to implement with the current state of verifying bodies and pathway participants. The LCFS has currently over 400 pathway codes ranging from Biodiesel to Renewable Gasoline. The producers of these fuels range from large firms to small independent producers. White acknowledges that the verification rulemaking makes some exception for producers of small credit volumes but believes that the remaining participants will still face difficulties in complying with certain measures of the rulemaking. (WE1_78-1)

Comment: LADWP recommends ARB consistently apply its policy such that any fuel using the Lookup Table pathways, including CNG, is exempt from any third-party

verification/validation. Alternatively, as mentioned above, LADWP recommends creating a threshold for credit generation for which any entity may be exempt from verification. LADWP reiterates its recommendation for regulatory flexibility to entities with small CNG operations, to avoid additional cost burden associated with third-party verification/validation. (LADWP1_38-12)

Comment: 5. CalETC supports the draft regulation order's proposal for grid-electricity LCFS to be exempted from the third-party verification provisions for quarterly fuel transaction reports and similar charging station registration requirements.

…

5. *CalETC supports the draft regulation order's proposal for grid-electricity LCFS to be exempted from the third-party verification provisions for quarterly fuel transaction reports and similar charging station registration requirements.*

For most fuels, but not grid-electricity[6], the draft regulation order proposes to supplement the work of CARB staff with a verification system that would require regulated entities reporting to CARB under the LCFS to retain the services of independent, accredited, third-party verifiers. LCFS verifiers would perform GHG accounting checks in a role similar to the independent, objective evaluations of organizations' financial reports by financial auditors. CalETC supports the addition of third-party verifiers in LCFS. CalETC agrees with the draft regulation order that LCFS credits generated by EDUs for grid-average electricity should not be subject to third-party verifiers for either the pathway or the fuel supply equipment or fuel transaction data (e.g., monitoring plans, data checks, sampling plans). Utilities are heavily regulated and the reporting requirements for utilities are more onerous than for other fuels, e.g., other fuels are not required to demonstrate that proceeds are returned to drivers. Additionally, the utility calculations for LCFS credits are largely a result of data points originating from CARB, unlike other credit generators.

[6] Electricity is not listed as subject to third-party verification for quarterly fuel transaction reports in Section 95500 c) 1) but electricity look-up table pathway applications and Tier 2 pathway applications would be subject to third-party verifiers.

(CALETC1_96-7)

Comment: 19. CalETC recommends the draft regulation order be amended to remove burdensome requirements for meter calibration, particularly for residential utility customers and meters for financial transactions.

…

19. CalETC recommends the draft regulation order be amended to remove burdensome requirements for meter calibration, particularly for residential utility customers and meters for financial transactions.

CalETC requests the Board direct staff to amend the metering provisions for residential electricity meters in the proposed regulation. Section 95483.2(b)(8) in the draft regulation order proposes that "…for natural gas, **electricity**, propane, and hydrogen must register all fueling supply equipment in the LRT-CBTS using the FSE registration

template available on the LRT-CBTS home page" and meet meter calibration requirements. Since residential electricity meters meet the financial meter standards in the referenced Mandatory Reporting Regulation (MRR section 95103(k)(7) - Measurement Accuracy Requirements), and since EDUs have a minimal number of residential customers with separate meters to measure the electricity used to charge EVs, we believe that the level of detail requested is unduly burdensome,[18] particularly since a minimal population of customers impacted will result in any measurable change to reported electricity of base LCFS credits issued to utilities. CalETC does not believe it is appropriate to do calibration for meter accuracy for CARB and for the California regulators who regulate electricity meters.[19] CalETC recommends the draft regulation order be amended to remove burdensome requirements for meter calibration.

[18] For example to gain access to the residence for testing of the meter, or having to test for CARB purposes when the meter is already regulated by other California agencies.

[19] CPUC, Governing Boards of publicly-owned utilities and the Division of Measurement Standards in the California Department of Food and Agriculture.

(CALETC1_96-22)

Agency Response: Staff declined to raise the threshold for eligibility of deferred verification or to expand exemption from verification, including for small station dispensing fossil compressed natural gas (CNG). Staff's proposed thresholds and eligibility criteria are sufficient to achieve cost reduction for small credit-generating projects with low risk to program integrity or the credit market. Raising the threshold could put an unacceptable number of credits at risk of invalidation over multiple annual compliance periods, because credits are issued prior to verification of historical data. The MRR threshold of 25,000 MT CO_2e of covered emissions is not applicable in the LCFS context, because it determines applicability of the compliance obligation in the Cap-and-Trade Program (allowances that must be retired). LCFS credit generators receive a financial benefit that must be rigorously reviewed. The analogy under Cap-and-Trade would be the issuance of offset credits to offset projects. These offset credits are based on reported and verified data and issued after the verification process is complete. Please also see Response O-2.1 in this chapter regarding staff's outreach efforts to ensure a smooth transition to the proposed verification program.

Staff did not make a change to exempt all entities using Lookup Table fuel pathways from verification, because some are, or will become, deficit-generating fuels. Staff did not create a threshold to exempt credit-generating entities from verification as explained above. Staff did change the eligibility criteria for deferred verification to include gaseous fuels. Please also see Response O-4 in this chapter regarding verification frequency.

Staff modified the original proposal (sections 95500(b)(2)(B) and (c)(2)(B)), to include non-liquid alternative fuels and deficit-generating alternative fuels in the eligibility threshold for deferred verification, excluding fuel pathways with biomethane using book-and-claim accounting. Expanding eligibility for verification deferral is necessary for consistency and will help small fossil CNG and fossil LPG facilities (previously opt-in fuels) to participate in LCFS. Please

also see Response D-3.1, Exemption and Phase-In Period for Removal of Opt-In Status for Small Station Dispensing Fossil Compressed Natural Gas, in this chapter. Biomethane is a fuel that can be high risk for accounting errors and double counting, therefore, biomethane must be verified annually to meet the regulatory requirements. CARB staff do not believe that many biomethane fuel pathway holders using book-and-claim accounting would be affected by this requirement because they typically generate more than 6,000 credits per year. In addition, biomethane suppliers also voluntarily participate in U.S. EPA's QAP program which requires quarterly audits and semi-annual site visits due to the risk of RIN invalidation. CARB staff anticipates that LCFS biomethane verification would occur at the same time as QAP audits for efficiency as QAP auditors seek and maintain accreditation to conduct LCFS verification services.

Note that, as stated in the ISOR on page III-145, CARB staff does not consider third-party verification necessary during this rulemaking for electricity (and hydrogen, excluding pipeline biomethane used for SMR). Since electricity used for transportation is expected to primarily be credited through Lookup Table pathways, and is based on metered data, staff expect data assurance needs will continue to be within the staffing capacity of CARB to conduct periodic compliance audits. Staff would like to clarify that its proposal does not require validation of electricity look up table pathway applications or Tier 2 EER pathway applications, since neither would include site-specific CI data.

Staff would like to clarify that in the proposed regulation FSE registration is optional for reporting metered electricity for residential EV charging to generate base credits. Further, only the entities responsible for obtaining a third-party validation or verification are subject to the meter calibrations requirements that one commenter is referring to in section 95491.1(c)(1)(G). As electricity reported for residential EV charging is not subject to third-party verification requirements, the meters used for measuring electricity used for residential EV charging are not subject to meter calibration requirements as set forth in section 95491.1(c)(1)(G).

O-7. Multiple Comments: *Fuel Pathway Allocation Accounting for Alternative Liquid Fuels: Commingling and Preventing Double Counting*

Comment: The approach chosen will increase complexity and risk of fraud, as independent verifications will take place without the option to assess supply and delivery in international supply chains and to different regulatory systems. This could result in double-claiming of certain feedstock characteristics and CI numbers. (ISCC1_22-3, UIC1_25-3)

Comment: Apart from cost, the use of existing, proven certification systems can help prevent double counting of the same material. (RV1_24-2)

Agency Response: Staff intends that the liquid fuel accounting requirements for multiple fuel pathways should prohibit double counting and has made the change

in the proposed regulation in section 95491(d)(1)(C) regarding fuel pathway allocation for produced fuel.

LCFS verification would include reviewing all feedstock inputs and fuel production regardless of final market to assure no double counting of feedstock attributes. The proposed change to clarify this intent specifies that feedstock attributes must be counted as processed (subtracted from the inventory accounting system) for all fuel produced in every quarter, not just fuel delivered to California and reported in the LRT. The balance period for fuel pathway allocation to produced or sold fuels is clarified as the reporting period for fuel transactions reports, which is quarterly. Staff clarified in the 2nd 15-day changes that a negative quarterly balance is not permitted. Only quarterly balance closure must be maintained for compliance and demonstrated during verification. Fuel reported in the LRT would use the yield calculation specified in the regulation or an allocation method approved by the Executive Officer. The CI calculators use monthly inventory to calculate the operational CI, initially to determine the certified CI, and then to demonstrate fuel pathway compliance each year. While CI calculators are a useful tool, they are not required to demonstrate compliance with fuel pathway allocation accounting and LRT reporting requirements.

O-8. Multiple Comments: *Harmonize with U.S. EPA Requirements*

Comment: However, we are concerned that the process may be highly duplicative of existing third-party verification we are already obtaining under the Federal Renewable Fuel Standard. As such, we've asked that you consider creating a complementary system whereby CARB would accept a valid federal certification and add any additional California-specific information that can be verified separately. We suggest that this be done on a pilot basis to ensure feasibility. (RCNG2_T43-4)

Comment: Clean Energy recommends Staff to partially exempt LCFS regulated entities who already participate in the RFS QAP program from the LCFS verification requirements with the exception of CI calculation and verification. Methodologies for tracking and allocation of renewable fuel are the same under both the LCFS and RFS regulatory programs, which means that the LCFS verification program should serve as a complementary level of verification for matters not covered under an RFS QAP program. Creating this complementary verification structure reduces costs of verification for entities already enrolled in QAP programs and allows for a larger pool of qualified verification providers, especially if the scope of LCFS verification can be limited to CI verification using the fuel specific simplified calculators. (CE1_92-13b)

Comment: To speed up review and audit, Third Party Verifiers should be utilized in a similar way as the EPA Renewable Fuel Standard's (RFS) Quality Assurance Program (QAP). AMP recommends that ARB staff consider utilizing reporting overlaps between the LCFS Verification program and RFS QAP program. These include Independent Engineering visits, Operational data collection and quarterly affidavits for all entities involved in the pathway. Keeping similar requirements for both programs reduces the

administrative burden placed on the project developer and can help streamline record keeping to achieve ARB's goal. (AMP1_86-4b)

Comment: Structurally, we are pleased to see significant overlap between the LCFS verification requirements and those of the EPA's QAP audit requirements. Any potential for synergy between the two programs will be extremely valuable to both credit generators and reporting parties. Given the number of regulatory programs at the state and federal level that affect these same fuels and require some form of attestation or verification audits, any duplication of effort quickly becomes very expensive. (CHEVRON1_112-28)

Comment: We also recommend that CARB explore how the sustainability verification can be aligned with the existing Quality Assurance Program for the U.S. RFS, which some producers will already be familiar with. (ENERKEM1_135-8)

Comment: C. CARB's verification program should be designed in a way that maximizes synergies with existing reporting, recordkeeping, and auditing requirements under the Renewable Fuel Standard (RFS).

Much of the information that must be verified under CARB's draft verification program is already reviewed and verified by third-party auditors for the RFS program. Specifically, every renewable fuel producer undergoes an annual RIN attest engagement, which requires auditors to verify operational data and other information. Further, EPA has approved RIN generation pathways for many ethanol producers through the Efficient Producer Pathway and conventional pathway petition processes. Monitoring plans related to these pathways are reviewed by third-party auditors annually to ensure valid RIN generation.

Further, some biofuel producers (particularly advanced and cellulosic) use third parties to administer EPA-approved RIN Quality Assurance Plans (QAPs) to provide additional assurance and validation to counterparties. CARB should strive to ensure its verification program capture synergies with these existing verification programs rather than "re-creating the wheel." (RFA1_80-18)

> **Agency Response:** The U.S. EPA's RFS program and verification structure are similar to California's LCFS in some ways, and very different in other ways. The RFS requires third-party attest engagements to verify RIN generation. In contrast, staff proposed mandatory third-party verification to a standard of reasonable assurance for the LCFS. The LCFS regulation has unique data requirements, where each alternative transportation fuel produced and used in California has its own CI and, based on the CI and quantity used in California, generates credits, which can be used to fulfill the compliance CI target, which declines over time. Data types subject to verification under the proposed program include initial validation of fuel pathway applications (CIs) and ongoing verification of operation CIs and fuel quantities. The proposed program would also include ongoing verification of petroleum data, including data reported by project applicants to calculate innovative crude and refinery credits, quantity

reports to determine gasoline and diesel deficit claims, and crude oil volume reports. Much of this data is not checked under the RFS, including under the voluntary QAP program. Therefore, staff proposed a mandatory third-party verification program specific to the LCFS, while recognizing some similarities with the RFS and leveraging those areas that are appropriate.

CARB staff has reached out to audit firms that provide attest engagement services and QAP services to encourage them to seek accreditation by CARB to offer LCFS verification services should this rule be approved by the Board. This would help integrate requirements in both programs for audit efficiency, while maintaining separate oversight by CARB and U.S. EPA. Additionally, audits performed for U.S. EPA programs, including third-party engineering reports, may occur at the same time as LCFS verifications as long as the LCFS requirements are met. Similarly, monitoring plans may be combined for both programs as long as the LCFS requirements are met. With respect to the suggestion to implement on a pilot basis, see Response O-5 in this chapter.

O-9. Multiple Comments: *Specified Source Feedstock Requirements Should be Clarified and May Have Unintended Consequences*

Comment: We also believe that the specified-source feedstock guidelines could use additional clarity or optionality. Separate aggregator verifications would enable producers to simplify their feedstock verifications and enable aggregators to better market feedstocks to a variety of producers. (CHEVRON1_112-30)

Comment: The proposed rule language requires product transfer documentation for biodiesel and renewable diesel feedstocks from the point of origin to the fuel processing plant. In our experience, this is infeasible. Processing plants receive a bill of lading for each consolidated shipment of feedstocks. However, these documents do not revert back to the points of origin for the feedstock. Several points of origin can be used to supply product for a single rail car or truck, making it virtually impossible to tie the volume back to the exact source because the volume will be comingled. Many feedstock generators are very small and disparate but collectively provide sufficient material for large-scale processing. Tracking exact points of origin for each feedstock purchased from these many small providers will require the development and deployment of an entirely new system that will be extremely onerous for the suppliers, and may discourage them from participating at all if the paperwork burden outweighs the incremental benefits received from selling small volumes of feedstocks. (DGD1_69a-2)

Comment: Proposed rule language requires product transfer documentation for biodiesel and renewable diesel feedstocks from the point of origin to the fuel processing plant. ARB has not demonstrated the necessity of requiring this level of documentation from fuel providers. Processing plants receive a bill of lading for each shipment. However, these documents do not revert back to the point of origin for the feedstock. Several points of origin can be used to supply product for a single rail car or truck, making it virtually impossible to tie the volume back to the exact source because the

volume will be comingled. Many feedstock generators are very small and disparate but collectively provide sufficient material for large-scale processing. Tracking exact points of origin for each feedstock purchase from these many small providers will require the development and deployment of an entirely new system that will be extremely onerous for the suppliers and producers with very little benefit to the integrity of the program. The proposed documentation will thus incentivizing them to consider alternate low carbon markets to avoid the documentation complexity of the LCFS program. (VALERO1_69b-5)

Comment:

- "Feedstock First Collection Point" means the facility that aggregates and stores or treats feedstock materials collected from a point of origin. The first collection point may be upstream of the fuel production facility, or, if feedstocks are transported to the fuel production facility directly from the point of origin, the first collection point is the fuel production facility. "First-collection Point" means the facility that aggregates and stores or treats feedstock materials collected from a point of origin.
- "Specified Source Feedstocks" means feedstocks that require the chain of custody evidence specified in 95488.8(g)(1)(B) to be eligible for a reduced CI associated with the use of a waste, residue, by-product or similar material. Specified source feedstocks are identified in section 95488.8(g)(1)(A).
    - REG continues to have concerns around low carbon intensity (CI) fuel producers tracing feedstocks such as used cooking oil (UCO) back to the point of origin and/or maintaining records. We continue to maintain that a risk-based approach to regulating this area is critical. The main focus of regulatory activity should be upon those areas most at risk for *meaningful* fraud (meaningful meaning having a significant financial impact). Identifying each restaurant contributor of UCO should not be as important as ensuring the aggregator has appropriate records and can verify, based on analysis, the material is indeed UCO. As the European Commission noted in a letter to RED voluntary schemes like ISCC back in 2014,"…the risk of fraud committed at the level of restaurants can be considered to be relatively low. The risk will be higher at later stages of the chain of custody, e.g. for collectors of UCO, traders, or large producers where the waste oil is a considerable source of income. This should be reflected in the auditing rules. Several voluntary schemes have developed approaches where the focus of the auditing effort at the origin is placed on the collectors of UCOP.[1]"

[1] https://ec.europa.eu/energy/sites/ener/files/documents/2014_letter_wastes_residues.pdf

…

As noted in the definitions section above, we have concerns with [95488.8] (g) *Specified Source Feedstocks*. Based upon our reading in (B), we think option (1) will make it difficult for the North American Used Cooking Oil (UCO) market to participate in the

LCFS unless we do joint applications with all of our suppliers – which is not reasonable at this time. While registering as an ICC feedstock supplier is an option and we support ISCC as a system to be incorporated into the LCFS program, the current marketplace requires more flexibility for suppliers not currently in that program. Based upon discussions with CARB staff, we don't think that making all North American UCO suppliers ISCC certified is the intention, but we're struggling to interpret the rules otherwise. Failing to adequately resolve this issue not only puts small producers out of the market, it could jeopardize significant portions of the US UCO market.

Under (B)(3), we can ensure access to documents and people to contact with the feedstock supplier, but we believe if we are required to provide access to their facilities, a significant portion of suppliers will decline or ultimately opt out, robbing Californians access to lower carbon intensity fuels. (REG1_88-3b)

Comment: Regarding data checks, under (D)(1), REG recommends tracing data back to the Feedstock First Collection Point versus Point of Origin for reasons identified above (i.e. risk for UCO isn't at restaurant; it is at the point of aggregation). (REG1_88-31)

Comment: We are concerned with CARB's characterization of Used Cooking Oil ("UCO") as a feedstock with higher risk for mischaracterization that requires chain of custody evidence to the point of origin. While it is true that feedstocks with lower CIs are more attractive for financial reasons, we believe there are other ways to ensure compliance with the program that do not place an undue burden on producers or renderers. We offer the following suggestions:

- Require producers to submit a copy of the Separated Food Waste Plan that is necessary for federal Renewable Fuel Standard compliance rather than requiring duplicative information. This plan requires producers to list the names and addresses of their feedstock suppliers and the estimated travel distance for the feedstock. Producers should be allowed to rely on statements from suppliers for this plan when submitting pathway applications. Severe penalties should be limited to cases of fraudulent or other nefarious conduct, while those participating in the market in good faith should be provided a reasonable degree of latitude to cure defects in supplier information through assessment of deficits.
- Third-party verifiers should conduct a mass balance of the chemical inputs and outputs at plants. To convert used cooking oil to biodiesel, plants commonly utilize distinct levels of methanol, catalyst, and other process chemicals. A plant utilizing a virgin feedstock would use less methanol and catalyst for the conversion of triglycerides and would not utilize catalysts that esterify free fatty acids. A baseline should be established at validation and be verified by the third-party verifier. In addition, a plant utilizing used cooking oil would generate a lower quality glycerin co-product. We believe a mass balance of chemicals used in processing may be equally effective and yet far less burdensome than chain of custody tracking for restaurant grease.

- At the site visit and during CARB audits, representative samples should be collected from feedstock tanks and sent to a laboratory to check for certain markers that would help identify the type of oil present. (NBBCABA1_29-7)

Comment: § 95488.8(g)(1)(B) Specified Source Feedstocks

- EcoEngineers supports CARB's efforts to create more transparency in feedstock markets; however, we also caution against placing overly burdensome requirements on biofuel producers. The proposed record-keeping requirements for Specified Source Feedstocks require a fuel pathway holder that acquires Specified Source Feedstocks from 3rd party suppliers to maintain "information from material balance or energy balance systems that control and record the assignment of input characteristics to output quantities at relevant points along the feedstock supply chain between the point of origin and the fuel production facility." This may not be possible for biofuel producers who are not vertically integrated and who do not have the ability to force their suppliers to reveal this information.
- We recommend that CARB either allow the biofuel producer to maintain a letter of attestation from a 3rd party feedstock supplier or require access to directly audit the feedstock supplier. If CARB is going to directly audit the feedstock supplier, there should be more clarity on the roles and responsibilities of feedstock suppliers as Regulated Entities. (ECOENGINEERS1_B5-5)

Comment: In § 95488.8(g) CARB has clarified the requirements to be eligible for a reduced carbon intensity (CI) that reflects the lower emissions or credit associated with the use of a waste, residue, by-product or similar material. In order to ensure a level playing field for different wastes and residues, separated municipal solid waste (MSW) and non-recyclable commercial and industrial waste should be added to the list of specified source feedstocks. Post-sorted MSW is clearly a waste, which is produced regardless of the existence of a low carbon fuels project that could use the material as a feedstock. Furthermore, the use of this waste as a feedstock is associated with lower emissions than materials that are specifically created for use as a feedstock and lower emissions than the alternative management option for these materials which is landfill.

…

We recommend that separated municipal solid waste (MSW) and non-recyclable commercial and industrial waste be added to the list of specified source feedstocks and that section § 95488.8(g) clarify that the emissions at the point of origin of a waste or residue are zero. (ENERKEM1_135-2)

Comment: 1. It requests clarification regarding the specified source feedstock provision, §95488.8(g). When applied to Separated MSW, this provision could be interpreted to impose an impossible standard if a fuel producer were required to trace the Separated MSW back to the original waste generator. Fulcrum recommends a word change to resolve this ambiguity.

…

The specified source provision pertains to feedstock that is a "waste, residue, by-product or similar material." §95488.8(g)(1). The feedstock that Fulcrum will utilize to produce fuel, Separated MSW, clearly falls within the scope of this definition. For specified source feedstocks, the proposed regulation imposes additional obligations as follows:

> *(B) Chain-of-custody Evidence. Fuel pathway applicants using specified source feedstocks must maintain either (1) delivery records that show shipments of feedstock type and quantity directly from the point of origin to the fuel production facility, or (2) information from material balance or energy balance systems that control and record the assignment of input characteristics to output quantities at relevant points along the feedstock supply chain between the point of origin and the fuel production facility. Chain-of-custody evidence is used to demonstrate proper characterization and accurate quantity.(…)*[2]
>
> [2] 17 CCR §95488.8(g)(1). *(emphasis supplied)*

For a producer that utilizes Separate MSW as a feedstock, concern rises as to what is meant by "point of origin". Taken to an extreme in the municipal solid waste context, point of origin could require following the waste all the way back to the original generator. Given the method in which MSW is collected and transport, it is infeasible to trace the material back to the original generator. This ambiguity is not resolved by reference to the definitions, as point of origin is not included. However, there is a related term that is defined, Feedstock First Collection Point. The term is defined as follows:

> *"'Feedstock First Collection Point" means the facility that aggregates and stores or treats feedstock materials collected from a point of origin. The first collection point may be upstream of the fuel production facility, or, if feedstocks are transported to the fuel production facility directly from the point of origin, the first collection point is the fuel production facility'*[3]
>
> [3] 17 CCR §95481(a)(44).

As applied to Separated MSW, it would be feasible to obtain chain-of-custody evidence to trace the feedstock back to the Feedstock First Collection Point. Fulcrum therefore requests that this term be substituted for the less precise "point of origin" in §95488.8(g)(1). (FULCRUM1_103-1)

Comment: This Comment requests clarification regarding the specified source feedstock provision, §95488.8(g). When applied to the feedstock that Safety-Kleen utilizes, used motor oil, this provision could be interpreted to impose an impossible standard if a fuel producer were required to trace the used motor back to the original source. Safety-Kleen recommends a word change to resolve this ambiguity.

…

The specified source provision pertains to feedstock that is a "waste, residue, by-product or similar material." §95488.8(g)(1). The feedstock that Emerald will utilize to produce fuel, UMO, falls within the scope of this definition. For specified source feedstocks, the proposed regulation imposes additional obligations as follows:

> *(B) Chain-of-custody Evidence. Fuel pathway applicants using specified source feedstocks must maintain either (1) delivery records that show shipments of feedstock type and quantity directly from the* ***point of origin*** *to the fuel production facility, or (2) information from material balance or energy balance systems that control and record the assignment of input characteristics to output quantities at relevant points along the feedstock supply chain between the* ***point of origin*** *and the fuel production facility. Chain-of-custody evidence is used to demonstrate proper characterization and accurate quantity.(…)*[2]
>
> [2] 17 CCR §95488.8(g)(1). *(emphasis supplied)*

For a producer that utilizes UMO as a feedstock, concern rises as to what is meant by "point of origin". Taken to an extreme in the UMO context, point of origin could require following the used motor oil all the way back to the original generator. Given the method in which UMO is collected and transport, it is infeasible to trace the material back to the original generator. This ambiguity is not resolved by reference to the definitions, as point of origin is not included. However, there is a related term that is defined, Feedstock First Collection Point. The term is defined as follows:

> *'"Feedstock First Collection Point" means the facility that aggregates and stores or treats feedstock materials collected from a point of origin. The first collection point may be upstream of the fuel production facility, or, if feedstocks are transported to the fuel production facility directly from the point of origin, the first collection point is the fuel production facility'*[3]
>
> [3] 17 CCR §95481(a)(44).

As applied to UMO, it would be feasible to obtain chain-of-custody evidence to trace the feedstock back to the Feedstock First Collection Point. Safety-Kleen therefore requests that this term be substituted for the less precise "point of origin" in §95488.8(g)(1). (SK1_104-2)

> **Agency Response:** Staff's proposal provides flexibility that allows feedstock suppliers that want to be recognized for lower CI operations to meet LCFS requirements by becoming a joint fuel pathway applicant. Staff's proposal relies on the verifier's professional judgement of risk in developing a plan for sampling chain of custody information for specified source feedstock to the point of origin. This approach provides reasonable assurance while not relying on strict chain-of-custody and management system certification along the supply chain as required by ISCC and implemented in the EU RED, and allows staff to continue to evaluate the risk of mischaracterizing low CI feedstocks in the LCFS program. Staff anticipates that most of the recordkeeping practices that support maintenance of ISCC certification will also support LCFS compliance and vice versa.

Staff worked with feedstock suppliers and alternate fuel producers to ensure the proposed documentation to demonstrate eligibility to claim the low-CI (specified source) feedstocks is clear for the typical scenarios encountered in supply chains. Staff agrees with the commenter that aggregators of specified source feedstocks should have the opportunity to separately verify their chain-of-custody and site-specific CI data to better market feedstocks to a variety of producers and included this option in its original proposal. For practical program administration purposes, staff's proposal allows aggregators to become joint applicants with fuel producers who intend to use aggregator's site-specific CI data in their fuel pathways. Joint applicants would be considered regulated entities.

The potential for significant additional LCFS credits being generated from specified source feedstocks for the same finished fuel justifies the additional documentation for such feedstocks. The material balance approach to chain-of-custody recordkeeping allows for commingling of feedstocks upstream of the fuel producer. Typically, the focus of feedstock verification will be at the fuel producer's facility, but may also include the first point of collection. Only very large suppliers that would be considered the point of origin, such as a large food processor supplying UCO, might be included in a verifier site visit. Staff is aware of, and agrees with, the European Commission's statement regarding low risk of UCO fraud at the level of restaurants. The purpose of reviewing a sample of UCO collection route records is to provide reasonable assurance that UCO quantities reported further along the supply chain are supported. Staff agrees with the commenters that MSW feedstock is more easily characterized than UCO or animal fat, and would not need documentation upstream of the first collection point to demonstrate reasonable assurance that it was not commingled with higher CI feedstocks. Used motor oil verification would be similar to used cooking oil verification.

The benefit of additional rigor is that it would provide reasonable assurance that ineligible feedstocks are not incentivized in the LCFS program. This benefit outweighs the potential disbenefit that some smaller feedstock suppliers or aggregators may choose not to participate. Note that UCO without proof of chain-of-custody could still be used for fuel production and reported under a higher CI fuel pathway. For this reason, staff disagrees that it would jeopardize significant portions of the U.S. UCO market. Staff has not been made aware of specific specified source feedstock suppliers that would object to providing reasonable access to their facilities for purposes of LCFS verification and believes the market will adjust to comply with these important requirements, necessary to protect program integrity, in order to benefit from the associated LCFS incentives.

Verifiers will sample chain-of-custody documentation and may require supplier/aggregator facility access based on their assessment of risk of material misstatement of the quantity of fuel reported under these low CI pathways. To mitigate potential risk, fuel producers should include references in their monitoring plans to their policies and procedures for ensuring they are correctly

reporting fuel produced under these low CI pathways. Some producers have rigorous supplier vetting procedures, require supplier attestations (consistent with the U.S. EPA RFS), and audit their suppliers to ensure compliance with attestations and contract requirements. In addition, the Separated Food Waste Plan required by U.S. EPA may provide a comprehensive picture of the feedstock supply chain for fuel pathways involving specified source feedstocks.

Staff agrees with the commenters that a risk-based regulatory approach and verification approach is critical; however, the purpose of regulatory oversight and verification of data quality is to detect reporting errors, whether or not they are the result of fraud. Errors erode program integrity whether or not fraud is involved.

Suggestions for alternative methods to demonstrate use of low CI feedstocks, such as mass balance of chemicals or laboratory analysis of feedstock are not likely to provide the rigor of reasonable assurance of no material misstatement due to feedstock commingling. However, fuel producers may continue to refine these methods for staff evaluation in the future.

Staff did not define a broad category of wastes and residues, because it would not provide sufficient staff review, or public review, and may inadvertently incentivize less common feedstocks. As part of the public rulemaking process, life cycle GHG emissions for common feedstocks are identified in the Simplified CI Calculators for Tier 1 fuel pathways and in CA-GREET3.0 for Tier 2 pathways. Less common feedstocks may be evaluated under Tier 2 by staff on a case-by-case basis, which allows for the careful consideration necessary to determine feedstock life cycle GHG emissions. In addition, Tier 2 pathways are posted for public review.

P. Alternative Diesel Fuel Regulation

P-1. Multiple Comments: *Sunset Provisions*

Comment: CARB proposes ADF mitigation continue until both on-road and off-road heavy-duty diesel engines have turned over to NTDEs.

1. CARB should bifurcate the on-road and off-road mitigation.

> Tax incentives should be suffienct to prevent on-road diesel from being used for off-road purposes. (FHR1_18-9)

Comment: The Alternative Diesel Fuel regulation currently includes a sunset provision for biodiesel that is initiated when 90% of the on-road "fleet" is comprised of New Technology diesel Engines (NTDEs), base on vehicle miles travelled. This benchmark was chosen because new diesel engine technology provides NOx neutrality, or even slightly reduced emissions, regardless of fuel type used. Therefore, once NTDEs reach a certain level of market penetration, NOx-reduction biodiesel additives no longer offer environmental or public health benefits.

We understand concerns about the off-road fleet transitioning more slowly than predicted when the ADF was originally approved by the board and, like CARB, we support addressing this issue by including the off-road market within the scope of the regulation. However, we fail to understand why both on- and off-road fleets must transition to NTDEs before either fleet may receive a sunset from the mitigation requirement, especially since numerous natural barriers exist—tax, economic, and otherwise—that keep these fuel pools segregated from one another.

As we understand it, the on-road fleet is expected to reach 90% NTDE penetration in the 2022-2023 timeframe, while the off-road fleet is not expected to reach that level until much later—not before 2030. Because of the markedly different turnover rates between the on- and off-road fleets, we do not believe biodiesel used in the on-road market should have to be mitigated once the segment has met the 90% threshold—the point at which NOx neutrality or better has been achieved. *The logical path is to require NOx mitigation only in the fleet that necessitates it*—in this case, the off-road fleet after 2023.

We appreciate CARB citing the possibility and benefits of "bifurcating" the on- and off-road fleets in the proposed regulation. Our members strongly support this approach so that on- and off-road fleets would sunset independently of one another resulting, in CARB's words, "in an earlier anticipated sunset date for on-road vehicles while preventing any NOx increases above the baseline[3]." Bifurcating the fuel pools in this way would provide two obvious advantages:

1) LCFS compliance costs would decrease, modestly on a per-gallon basis but materially across the broad spectrum of on-road diesel fuel; and

2) CARB's regulatory burden would be reduced since the volume of fuel requiring oversight for ADF compliance purposes would be dimished by at least 75%.[4]

[3] Appendix G, Draft Supplemental Disclosure of Discussion of Oxides of Nitrogen Potentially Caused by The Low Carbon Fuel Standard, Page G-7, California Air Resources Board, March 6, 2018.

[4] Adjusted Sales of Distillate Fuel Oil by End Use, Petroleum and Other Liquids, U.S. Department of Energy, U.S. Energy Information Administration, December 19, 2017.

While bifurcating the on- and off-road requirements is undoubtedly the superior regulatory approach, we understand that different viewpoints can arise on most any subject, regarldless of how benign the issue or how obvious the proper conclusion may be. For this reason, we have identified potential concerns about bifurcationg the two fuel markets and provided our thoughts on these scenarios.

In our view, the most likely potential criticism of a bifurcated regulatory system is that someone could purchase unadditized on-road fuel and use that product in off-road applications, thereby avoiding the cost of additizing biodiesel. While this could in theory occur, doing so would be a clear violation of the law. In addition, there is no financial incentive to violate the law in this manner since the value of the road tax exemption once receives with the purchase of dyed diesel exceeds the cost of additization by a factor of at least three. In other words, the economics strongly incentivize compliance.

Another scenario that could be raised, albeit far less likely, includes a fuel user purchasing on-road fuel for off-road purposes and then applying for a tax refund at the end of the quarter or year, depending on the circumstance. The fuel user could theoretically purchase on-road, unadditized fuel for use in off-road applications and recoup the tax exemption at a later date.

So how likely is this to occur? We think not very likely for a variety of reasons. First, the costs of additization are a fraction of the value of the tax exemption and therefore would not seem significant enough to materially change the financial calculus. In other words, if a particular fuel purchaser was unwilling to break the law for 36 cents per gallon (the cost of additization plus the tax refund[5]).

[5] https://www.arb.ca.gov/lists/com-attach/11-lcfs18-VDgHYlUyWHgEXVAi.pdf.

A review of figure from the California Department of Taxes and Fees Administration (CDTFA) shows that, in fact, the total amount of excise tax refunds sought has remained relatively static over the years and represents a small percentage of the total off-road gallons sold on an annual basis (0.0082% in 2016)[6]. This would seem to indicate that if violations are indeed occurring, they represent an exceedingly small portion of overall fuel sales. Moreover, these purchases are audited by CDTFA, further decreasing the likelihood of illegal activity. If anything, adding another layer of criminal charges and oversight by an additional government agency (CARB) decreases rather than increases the likelihood of such activity. Ultimately, we believe this scenario is too remote to merit serious consideration.

[6] Off Highway Analysis for Years 2007-2016, Business Tax and Fee Division, California Department of Tax and Fee Administration.

Nevertheless, to fully exhaust the conversation, let us consider the example of the off-road agriculture sector where a regulatory structure exists to ensure that fuel purchasers and users abide by the law. In this sector, the purchaser can also qualify for a sales tax exemption when purchasing diesel fuel. To do so, the purchaser must sign an exemption certificate, under penalty of perjury, which declares the use of the fuel for agricultural purposes and indicates whether it will be used in the on- or off-road market. This exemption certificate is retained by the fuel distributor and subject to audit by the CDTFA. The additional layer of government oversight on this particular industry seems to make the potential for gaming the system to avoid the cost of additization evern more remote.

In terms of general enforcement by CARB, a clear record exists of fuel purchasers who have claimed tax refunds.[7] This information could be used to aid in enforcement because those who claim the exemption are the only individuals who have potential to engage in fraudulent activity. In addition, aggregated data is publicly available from CDTFA. Therefore, CARB will know: a) who the pool of potential fraudulent actors is; and b) whether exemption claims—and therefore *potential* fraudulent activity—has increased against the pre-2019 baseline. The mechanism for conducting compliance reviews would be exactly the same as if CARB were auditing the entire diesel fuel pool. By simply reviewing bills of lading (BOLs), which are required to be maintained for LCFS compliance purposes, fuel purchasers would need to demonstrate that they purchased an amount of additized biodiesel equivalent to the fuel claimed on tax exemption requests.

[7] https://www.cdtfa.ca.gov/formspubs/cdtfa101.pdf.

Even if CARB chooses not to utilize individual or aggregated information from other agencies, the fact remains that the pool of fuel purchasers who need to be monitored and possibily audited would be reduced by at least 75%. This is, in and of itself, an enormous benefit to the agency.

In conclusion, we support the bifurcated regulatory structure CARB proposed in Appendix G because it facilitates attainment of LCFS goals and minimizes CARB's enforcement responsibility. Bifurcation of the ADF requirement for on- and off-road fleets is the obvious solution to the off-road issue CARB has identified and we strongly support the agency moving forward with implementation of the concept through this regulation. (NBBCABA1_29-4)

Comment: Very appreciative of the comments we heard today around the ADF and the potential bifurcation between on-road and off-road. I think that's very important. I think there's definitely a path forward when we look at how dyed diesel moves in the State. So we look forward to working with staff on that. (REG2_T16-4)

Comment: So the only think I'd add to that today and ask that you consider is that we are supportive of the comments made by staff to review in the 15-day comment period the idea of bifurcation for the biodiesel industry, and believe that that is a logical step forward, dealing with the ADF issue and some of the concerns raised by the POET litigation.

So we fully support the proposal of bifurcation and look forward to working with you and the staff as you move forward. (NBBCABA2_T23-2)

> **Agency Response:** Staff appreciates the support for bifurcating the ADF sunset provision. Staff proposed bifurcating the ADF sunset provision for on-road and off-road separately, to reflect the slower fleet transition rate for the off-road engine market. The on-road sunset provision is based on the vehicle miles traveled by heavy-duty on-road NTDEs rather than vehicle number. The off-road sunset provision is based on the hours of operation of heavy-duty off-road new technology diesel engines (NTDEs).

P-2. ***Fuel Property Reporting in the Alternative Diesel Fuel Regulation***

Comment: 9. Modify the references to ASTM Methods in the regulation on Commercialization of Alternative Diesel Fuels

In the Regulation on Alternative Diesel Fuels, Tables outlining fuels properties should be harmonized with the referenced ASTM Standard. For example, ASTM D6751 (http://www.astm.org/Standards/D6751.htm), Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, defines a minimum flash point in ºC, while Table A.8 calls for results to be report in ºF. Ensuring technical and regulatory reporting formats match as closely as possible will make reporting easier and result in fewer mistakes. (LANZATECH1_77-11)

> **Agency Response:** The ADF regulation refers to temperatures in ºF to be consistent with other California fuels regulations.

Q. Voluntary NOx Remediation Measure Funding and Draft Supplemental Disclosure Discussion of Oxides of Nitrogen Potentially Caused by the Low Carbon Fuel Standard Regulation

Q-1. *Support for the Voluntary NOx Remediation Measure Funding and the Draft Supplemental Disclosure Discussion of Oxides of Nitrogen Potentially Caused by the Low Carbon Fuel Standard Regulation*

Q-1.1 Multiple Comments: *Support for the Draft Supplemental Disclosure Discussion of Oxides of Nitrogen Potentially Caused by the Low Carbon Fuel Standard Regulation*

Comment: A fair amount of conversation has occurred around the POET, LLC v. California Air Resources Board case and biodiesel's theoretical NOx impacts on air quality. We would like to briefly speak to this issue because we are not convinced it is well understood.

First, while we understand the court's strict interpretation of CARB testing data and its conclusion that a NOx impact with biodiesel above certain volumetric thresholds exists, we—and the National Renewable Energy Laboratory—disagree that the results are measurable, significant, or outside the margin of testing error. More in line with our view on the subject, we were pleased to read the following summarizing text from page 2 of CARB's Appendix G:

> "Overall, biodiesel attributable to the LCFS is beneficial in terms of health impacts for all years considered. In fact, staff found that any use of biodiesel, with or without offsetting factors, would be considered beneficial in terms of overall health impacts because the health benefits from particulate matter (PM) reductions outweigh the health impacts from any NOx increases. That is, as an overall air quality matter, LCFS-attributable biodiesel increases improved health outcomes in all years."

As CARB notes, biodiesel is beneficial not only in terms of carbon reductions but also overall air quality and associated public health. The following chart, which summarizes emissions from biodiesel and renewable hydrocarbon diesel compared to CARB diesel, provides insight into why this is the case[1].

[1] Emissions data excerpted from the following sources: Pages G-31 and G-32, Appendix G, Draft Supplemental Disclosure Discussion of Oxides of Nitrogen Potentially Caused by the Low Carbon Fuel Standard, CARB, March 6, 2018; Executive Order G-714-ADF01 approval for Vesta 1000 NOx additive; and Evaluation of the Impacts of Biodiesel and Second Generation Biofuels on NOx Emissions for CARB Diesel Fuels, Durbin et al, July 12, 2012.

Biodiesel

Engine Type	B20 NOx	B20 PM
Non-NTDE	+1.5-+4%	-19%
NTDE	0.0%	-19%

Biodiesel (Additized)

Engine Type	B20 NOx	B20 PM
Non-NTDE	-1.9%	-18%
NTDE	0.0%	-19%

Renewable Diesel

Engine Type	R20 NOx	R20 PM
Non-NTDE	-2.9%	-4%
NTDE	0.0%	-4%

(NBBCABA1_29-2)

Comment: Neste supports staff's efforts to respond to the court's concerns about NOx addressed in the writ of mandate in the *POET* lawsuit. Neste believes that the supplemental environmental analysis included in Appendix G is adequate and that it together with the additional ADF sunset requirements comprehensively addresses the potential of LCFS-driven biodiesel NOx emission impacts. (NESTE1_76-11)

Comment: Outside of the letter that the health organizations put in, the Lung Association just wanted to say thank you to the staff for your continued work on the biodiesel NOx issue. We know this is such an important element of the program and we've been supportive of that throughout, and continue to support your work on that. (HMO2_T15-6)

Comment: A lot has already been said to say the least, so I will just echo a few comments I've already heard today. The first echoing staff's and American Lung Association's concern for NOx emissions produced by biofuels -- some biofuels. Research supported by the Ford Motor Company found that a Ford F-350 fueled by biodiesel produces more NOx emissions than the same pickup truck fueled by petroleum diesel. And coming from a region where diesel trucks are the largest sources of NOx, this is a concern for us.

So I appreciate staff highlighting this, and working on it as we move forward, and would support CARB's oversight ensuring that climate programs like low carbon fuel standard are not negatively impacting air quality. (CVAQ2_T46-1)

> **Agency Response:** Staff acknowledges the commenters' support of staff's conclusions related to the overall air quality and public health benefits of biodiesel use attributable to the LCFS.
>
> Staff also appreciates the support for the supplemental environmental analysis included in Appendix G of the ISOR. Staff agrees that the supplemental environmental analysis, together with the additional ADF sunset requirements included in the Proposed Amendments to the LCFS and ADF Regulations, comprehensively addresses the potential for LCFS-driven biodiesel NOx emissions impacts.

Staff appreciates the support from HMO and CVAQ on staff's work on the biodiesel NOx issue.

Staff have found that light-duty and medium-duty vehicles do not experience increases in NOx emissions due to the use of biodiesel.[55] These findings were based on studies comparing the NOx emissions associated with biodiesel use versus conventional diesel use in a variety of diesel-fueled passenger cars and trucks, including a Ford F-350.[56,57]

Q-1.2. ***Support for the Voluntary NOx Remediation Measure Funding***

Comment: Alan Abbs from CAPCOA, here to support the mitigation program as proposed by staff.

We worked with staff on the proposal and believe that using the Carl Moyer process and specifically the State reserve process for Moyer funding is a way to get projects completed fast in districts where most of the excess NOx emissions were likely to have occurred.

And so, yes, we support staff proposal on that. (CAPCOA1_T1-1)

Agency Response: Staff acknowledges the commenter's work on and support for CARB's Voluntary NOx Remediation Measure (VNRM) grants. Staff agrees that the VNRM grants, using the Carl Moyer process, will allow for timely completion of projects in air districts where most of the excess NOx emissions were likely to have occurred.

Q-2. ***Alternative Diesel Fuel Bifurcation***

Comment: Section 3. b., page G-7

"During the rulemaking process, staff will continue to evaluate whether the sunset provision can be bifurcated for on-road vehicles versus off-road vehicles and equipment, which would result in an earlier anticipated sunset date for on-road vehicles while preventing any NOx increases above baseline."

Following are California Fueling's comments regarding "bifurcation":

The bifurcation concept has significant practical challenges. In today's marketplace, BXX blends are splash blended (as opposed to in-line blending). If the on-road ADF were to expire NOX Mitigant would not be required. Meanwhile, the off-road ADF would

[55] Staff Report: Multimedia Evaluation of Biodiesel. Multimedia Working Group, California Environmental Protection Agency. May 2015.

[56] Performance and Emissions of Diesel and Alternative Diesel Fuels in Modern Light-Duty Vehicles, SAE 2011-24-0198. Nikanjam, Manuch, et al., September 11, 2011.

[57] Regulated Emissions from Biodiesel Fuels from On/Off road Applications, Atmospheric Environment, Volume 41, p. 5647-5658. Durbin, Thomas et al., 2007.

remain intact, requiring NOX Mitigant. As a result, infrastructure challenges would surface. For example, when >B5 blends are splash blended “under the rack”, NOX Mitigant is added to biodiesel in bulk storage tanks or in railcars (making it “additized”). Should under the rack blenders be required to “additize” biodiesel railcars or bulk storage tanks for off-road and not for on-road, they would be required to double the number of tanks, railcars, etc. This likely would not occur because of increased costs, limited asset availability, etc. and, as a result, off-road B20 volumes could be negatively impacted. The same would hold true for terminal blending given they too splash blend BXX in tankage, however, at present, terminals are only blending seasonal allowances which do not require NOX Mitigant.

Terminals represent the single largest opportunity to promote B20 blends, yet few are doing so. Terminal clients, or obligated parties, dictate BXX blend levels. In order for terminals to invest in BXX blending equipment and infrastructure, their clients would have to be willing to assume those costs. In a moving target scenario, (e.g. different on and off-road sunset dates), terminal clients will be less likely to invest the capital required to rack blend B20 because of the timing payback uncertainty.

Biodiesel represents one of the key opportunities for fossil fuel replacement. Given the amount of off-road diesel in California ("'30-35% of the total diesel fuel consumed in California), a significant portion of the diesel market may be precluded from using biodiesel from a practicality perspective if a bifurcation concept was adopted. Off road diesel vehicles emit >250 tons per day of NOX emissions as well as additional particulate matter. The off-road diesel market could become one of the highest criteria pollutant emitting fuels if access to renewable fuel options is made difficult. Citizens of California in areas of high off-road vehicle populations face potential increased exposure of criteria pollutants should off-road B20 ADF volumes be negatively impacted because of bifurcation.

In summary, the current ADF applies to on and off-road BXX blends above seasonal allowances. However, if the on-road ADF sunsets, but the off-road ADF remained intact, the off-road B20 market would likely be negatively impacted because of the increased infrastructure requirements of supplying two fuel types. (CAF1_9-1)

> **Agency Response:** Please see response to comment CAF2_FF2-0 in the Responses to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

R. Economic Analysis

R-1. *Comments Related to the Standardized Regulatory Impact Assessment*

R-1.1. Comment: Here, while the SRIA includes several figures regarding the adverse economic impacts of the LCFS, the SRIA does not explain how these negative impacts will affect existing businesses; rather the SRIA merely states there will be no change in competitive advantage or disadvantage based on assumptions that other states could adopt versions of the LCFS. If the Executive Officer adds such an explanation now, including by way of testimony or presentations to the Board, or other communications, the requirement of Section 11347.1 (a) would apply. (GROWTHENERGY1_B4-15)

> **Agency Response:** The Standardized Regulatory Impact Assessment (SRIA) discusses in different sections the potential adverse economic impacts that adoption of the proposed amendments will have on the California economy and businesses. In section C. of the SRIA, staff estimates and discusses in detail the direct costs that California businesses will incur due to the proposed amendments. Section C. also contains a calculation of the total costs that will be incurred by a typical refinery in California, since "staff expects that the costs of complying with the proposed amendments would fall initially on oil refineries".
>
> The SRIA also contains another section that discusses the macroeconomic impacts of the proposed amendments on the California economy, titled section G. In section G., staff provides details on the potential effects on the size of the California economy, number of jobs, and other macroeconomic variables due to the proposed amendments.
>
> The commenters have misunderstood staff's analysis of competitiveness of businesses in California. Staff acknowledged in the SRIA that the proposed amendments may negatively affect the competitiveness of some California businesses. The SRIA states that "California sectors that rely heavily on transportation fuel may also face higher prices, resulting in a competitive disadvantage relative to out of state entities that are not subject to the LCFS." (ISOR, Appendix E, pg. 69). Staff however argues that if other jurisdictions adopted policies similar to the LCFS "businesses outside of the state will likely begin to face similar carbon costs in order to reduce GHG emissions, reducing the relative impact of the proposed amendments on California businesses." *(Id.)*

R-1.2. Comment: Under the APA, state agencies proposing to "adopt, amend, or repeal any administrative regulation" must first perform an assessment of "the potential for adverse economic impact on California business enterprises and individuals." (Govt. Code, § 11346.3, subd. (a).) Among other things, the APA requires that agencies such as CARB prepare a Standardized Regulatory Impact Assessment ("SRIA") analyzing "the potential adverse economic impact on California business and individuals of a proposed regulation," (Govt. Code, § 11346.3), and declare in the notice of proposed action any initial determination that the action will not have a significant statewide adverse economic impact directly affecting business. (Govt. Code, § 11346.5,

subd. (a)(8); *WSPA, supra*, 57 Cal.4th at 428.) The APA requires the SRIA to evaluate several issues, including "elimination of jobs within the state," "the elimination of existing businesses within the state," and "[t]he competitive . . . disadvantages for businesses currently doing business within the state." (Govt. Code, § 11346.3, subds. (c)(1)(A)-(C).) The SRIA must be circulated with the 45-day materials (here, the ISOR), and must be supported by "facts, evidence, documents, [or] testimony," and made available for public review and comment for at least 45-days before an agency approves a regulation. (Govt. Code, §§ 11346.5, subds. (a)(7), (a)(8), 11347.3(b)(4).) The SRIA cannot be based on "mere speculati[on]". (*WSPA, supra*, 57 Cal.4th at 428.) "A regulation . . . may be declared invalid if . . . [t]he agency declaration . . . is in conflict with substantial evidence in the record." (*Calif. Ass'n of Medical Products Suppliers v. Maxwell-Jolly* (2011) 199 Cal.App.4th 286, 306.)

The current SRIA for the Proposed Amendments does not meet the applicable standards. The analysis of the LCFS regulation's "potential adverse economic impact on California business and individuals of a proposed regulation," (Govt. Code, § 11346.3), is contained on pages 69-70 of Appendix E to the ISOR.

The ISOR's discussion of the "the elimination of existing businesses within the state," and "[t]he competitive . . . disadvantages for businesses currently doing business within the state," (Govt. Code, § 11346.3, subds. (c)(1)(B)-(C)), does not fully address and take into account the ISOR's estimate that the LCFS regulation is projected to increase the price of gasoline up to $0.36/gallon and diesel by up to $0.44/gallon as early as 2025. (ISOR, Appx. E at 50.) The projected increase in the price of gasoline, which is directly attributable to the fact that the costs of the LCFS regulation are expected to be passed on to California consumers and businesses, is three-times higher than the controversial $0.12/gallon tax increase recently approved by the Legislature in 2017. (See SB 1: The Road Repair and Accountability Act of 2017.) In addition, the SRIA estimates that the LCFS regulation could result in a loss of over 25,000 jobs, (*id* at 63), and a 0.1% decline in the GDP. (*Id*. at 68.)

Although impacts of this nature would dramatically affect small businesses,[10] the SRIA does not consider whether the increase in the price of gasoline or diesel could result in "the elimination of existing businesses within the state . . . ." (Govt. Code, § 11346.3, subd. (c)(1)(B); *cf.* ISOR, Appx. E at 70.)

[10] Various entities have expressed concern about the impact of the $0.12/gallon increase on small businesses and families, many of which are summarizes in the following documents:

- http://www.next10.org/sites/default/filesltransportation- funding-brief-final.pdf
- http://www.nfib.com/content/news/california/small-business-reacts-to-passfe-of-senate-bill-1/
- https://www.nfib.com/content/analysis/california/semnate-bill-1-will-hurt-small-businsses-and-working-families/
- http://www.sacbee.com/news/politics-government/capitol-alert/article191161034.html
- http://www.latimes.com!politics/la-pol-ca-gas-tax-repeal-20171229-story.html

The SRIA's discussion of "[t]he competitive . . . disadvantages for businesses currently doing business within the state," (Govt. Code, § 11346.3, subd. (c)(1)(C)), also requires

augmentation. While the SRIA does recognize that "California sectors that rely heavily on transportation fuel may face higher prices, resulting in a competitive disadvantage relative to out of state entities that are not subject to the LCFS," the SRIA makes no attempt to quantify the extent of the competitive disadvantage a $0.36/gallon increase in gas prices or a $0.46/gallon increase in the price of diesel fuel would create.

The SRIA relies on the suggestion that other jurisdictions will adopt their own versions of the LCFS regulation. The SRIA states that "due to the 2015 Paris Agreement reached by the Conference of Parties in Paris, which is aimed at keeping the global temperature rise below 2°C, staff expects signatories (which include all of the U.S.'s trading partners) to take action to reduce GHG emissions." (ISOR, Appx. E at 69.) This assertion, however, is not supported by any "facts, evidence, documents, [or] testimony" to suggest the adoption of LCFS-like regulations by other jurisdictions would decrease the price of fuels, or otherwise reduce competitive harm to "businesses currently doing business within the state . . . ." (Govt. Code, § 11346.3, subd. (c)(1)(C).) Further, there is no evidence that a critical mass of states have actually adopted regulations similar to the LCFS, nor are there statutes like AB 32 in other states that might be used to try to justify programs in addition to the RFS program. The only state to which the ISOR points to adopting an LCFS regulation is Oregon, and at least one other state has declined to adopt an LCFS program like the one in California.[11]

[11] http://www.biofuelsdigest.com/bdigest/2015/07/03/washington-state-nixes-low-carbon- fuel-standard-via-transport-bill-poison-pill/

(GROWTHENERGY1_B4-31)

Agency Response: This comment argues that the SRIA did not adequately address the proposed amendment's potential for 1) elimination of existing businesses, 2) reducing the competitive advantage of businesses within the State.

For the first part, staff's analysis did not indicate that any specific business will be eliminated due to direct costs imposed by the proposed amendments. However, since transportation fuel is an input to many existing businesses, an increase in the cost of gasoline and diesel might have the effect of eliminating businesses within the State. However, existing businesses can also take advantage of the benefits provided to consumers of low carbon fuels which might reduce the total cost of transportation fuel faced by the business. Since the elimination or creation of businesses within the State occurs mostly due to the indirect costs and benefits of the proposed amendments, rather than direct costs and benefits, staff relied on a macroeconomic model that takes into account the complex interactions of the economy to come with an estimate of the economic impacts of the proposed amendments, including potential loss of jobs and private incomes. Unfortunately, these macroeconomic models cannot assess the number of businesses that will be created or eliminated, since businesses are heterogeneous in size and competitiveness within and amongst different sectors of the economy. Staff is not aware of a model that can estimate the number of businesses that will be created or eliminated due to a change in the price of

gasoline and diesel, and would welcome any input on how to address to improve its assessment in the future.

For the second part, please refer to Response R-1.1 in this chapter.

Moreover, the California Department of Finance reviewed staff's economic analysis and generally concurred with staff's proposed methodology.[58] Staff also addressed DOF's comments in the ISOR's economic chapter and Appendix E.

R-2. ***Cost versus Benefit of the Proposed Amendments***

Comment: RPMG recommends the Board direct staff to analyze the issue of increased costs compared to participation in the program, and work to neutralize and minimize their impacts on stakeholders. The examples throughout this comment letter highlight a pattern of the regulation which is to be very conservative at a cost to the producer and to the program. This overly conservative approach presents a cost structure that is punitive. Those new, additional, and yet unknown costs, coupled with a market pricing benchmark in which full CI credit generation potential based on the annual standard are not realized, squeeze low carbon ethanol economics from both sides. Midwest corn ethanol has been a stalwart component of the LCFS, and shall continue to be moving forward, but the cost structures presented send a very strong negative signal to all low carbon fuel producers.

The proposed regulation creates significant additional market barriers to fuel providers. These barriers come in several forms. The proposed LCFS adds costs and regulatory risk to biofuel producers while at the same time removes incentives to incrementally innovate or benefit from actual efficiency gains. (RPMG1_64-3)

Agency Response: Staff's economic analysis found that the additional costs imposed on starch ethanol producers by the proposed amendments are likely to be small compared to the benefits that starch ethanol producers will gain from them. As an illustration, a starch ethanol plant with a CI of 71 gCO_2e that produces 50 million gallons annually will generate more than 90,000 credits in 2019 which, at the average June 2018 price of $154, will generate about $13.9 million in revenues for this starch ethanol plant. The only additional cost that the proposed amendments will impose on starch ethanol is for third-party verification which staff estimates to impose an additional cost ranging from $30,000 to $54,000 annually, far below the value of the credits that the starch ethanol plant will accrue from the LCFS program.

R-3. ***Investments Outside the State***

Comment: And then the third one you heard -- or the last one you heard from another speaker, the credit generating businesses compared to the baseline scenario for the

[58] Department of Finance, Dec 22 2018. *ARB LCFS 2017 SRIA-Finance Comments.* http://www.dof.ca.gov/Forecasting/Economics/Major_Regulations/Major_Regulations_Table/documents/ARB_LCFS_2017_SRIA-Finance_Comments.pdf.

credits generated, 9.2 billion over that same period, but only three billion of it is in California.

So that means that investment, a large part of it is going outside the state. So it helps somebody's economy, but it would be nice if it helped our own. (WSPA2_T48-9)

> **Agency Response:** The LCFS is designed to be location neutral, and CARB designs provisions to insure CI reductions in California transportation fuel and to incentivize the innovation in low carbon fuels without regard to the share of credits that are generated in-state. However, the supporting economic analysis demonstrates that the proposed amendments are estimated to enhance opportunities for California businesses to generate credits related to activities in California.
>
> Based on staff's illustrative compliance scenarios, the proposed amendments are expected to increase the value of credits generated in-state by $2.6 billion cumulatively from 2019 through 2030 compared to the business-as-usual scenario. Meanwhile, the in-state cost of deficits generated is estimated to increase by $1.0 billion cumulatively from 2019 through 2030 compared to the business-as-usual scenario.
>
> Based on these estimates, the proposed amendments are expected to lead to a positive net impact on the California economy. In addition to these economic benefits, the proposed amendments are expected to provide additional positive health benefits to California residents, as well as significant reductions in GHG emissions from transportation in California. In sum, staff estimated that the proposed amendments will lead to a net benefit of $1.7 billion to California.

S. Environmental Analysis

S-1. Multiple Comments: *Comments on the Draft Environmental Analysis*

Comments: CAF1_9-2, CAF1_9-3, CAF1_9-4, CAF1_9-5, CAF1_9-6, CAF1_9-7, CAF1_9-8, CAF1_9-9, INNOSPEC1_51-1, SUNPOWER1_70-4, NRDC1_81-14, NRDC1_81-15, AJFP1_102-13, RCM1_114-1, NEXTGEN1_124-50, GROWTHENERGY1_B4-1, GROWTHENERGY1_B4-2, GROWTHENERGY1_B4-3, GROWTHENERGY1_B4-11, GROWTHENERGY1_B4-12, GROWTHENERGY1_B4-13, GROWTHENERGY1_B4-14, GROWTHENERGY1_B4-16, GROWTHENERGY1_B4-17, GROWTHENERGY1_B4-18, GROWTHENERGY1_B4-19, GROWTHENERGY1_B4-20, GROWTHENERGY1_B4-21, GROWTHENERGY1_B4-22, GROWTHENERGY1_B4-23a, GROWTHENERGY1_B4-23b, GROWTHENERGY1_B4-23d, GROWTHENERGY1_B4-23e, GROWTHENERGY1_B4-23f, GROWTHENERGY1_B4-23g, GROWTHENERGY1_B4-24, GROWTHENERGY1_B4-25a, GROWTHENERGY1_B4-25b, GROWTHENERGY1_B4-25c, GROWTHENERGY1_B4-25d, GROWTHENERGY1_B4-25e, GROWTHENERGY1_B4-25f, GROWTHENERGY1_B4-25g, GROWTHENERGY1_B4-25h, GROWTHENERGY1_B4-25i, GROWTHENERGY1_B4-25k, GROWTHENERGY1_B4-26, GROWTHENERGY1_B4-29, GROWTHENERGY1_B4-30, GROWTHENERGY1_B4-33, GROWTHENERGY1_B4-35, GROWTHENERGY1_B4-36, GROWTHENERGY1_B4-37, GROWTHENERGY1_B4-38, GROWTHENERGY1_B4-39, GROWTHENERGY1_B4-40, GROWTHENERGY1_B4-41, GROWTHENERGY1_B4-42, GROWTHENERGY1_B4-43, GROWTHENERGY1_B4-44, GROWTHENERGY1_B4-45, GROWTHENERGY1_B4-46, GROWTHENERGY1_B4-47, GROWTHENERGY1_B4-48, GROWTHENERGY1_B4-49, GROWTHENERGY1_B4-50, GROWTHENERGY1_B4-51, GROWTHENERGY1_B4-52, GROWTHENERGY1_B4-53, GROWTHENERGY1_B4-54, GROWTHENERGY1_B4-54a, GROWTHENERGY1_B4-54b, GROWTHENERGY1_B4-54c, GROWTHENERGY1_B4-54d, GROWTHENERGY1_B4-54e, GROWTHENERGY1_B4-54f, GROWTHENERGY1_B4-54g, GROWTHENERGY1_B4-54h, GROWTHENERGY1_B4-54i, GROWTHENERGY1_B4-54j, GROWTHENERGY1_B4-54k, GROWTHENERGY1_B4-54l, GROWTHENERGY1_B4-55, GROWTHENERGY1_B4-56, GROWTHENERGY1_B4-57, GROWTHENERGY1_B4-58, GROWTHENERGY1_B4-59, GROWTHENERGY1_B4-60, GROWTHENERGY1_B4-61, GROWTHENERGY1_B4-62, GROWTHENERGY1_B4-63, GROWTHENERGY1_B4-64, GROWTHENERGY1_B4-65, GROWTHENERGY1_B4-66, GROWTHENERGY1_B4-68, GROWTHENERGY1_B4-69,

GROWTHENERGY1_B4-70, GROWTHENERGY1_B4-71, GROWTHENERGY1_B4-72, GROWTHENERGY1_B4-73, GROWTHENERGY1_B4-74, GROWTHENERGY1_B4-101, GROWTHENERGY1_B4-108, ECOENGINEERS1_B5-13, ECOENGINEERS1_B5-14, ECOENGINEERS1_B5-15, ECOENGINEERS1_B5-16, ECOENGINEERS1_B5-17, STI1_B7-1, UCLA1_B8-10

Agency Response: The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

Comments NEXTGEN1_125-50, GROWTHENERGY1_B4-108, and ECOENGINEERS1_B5-14 are also responded to in this chapter in Responses J-14.1, J-14.2, and D-4.3d, respectively.

T. Fuel Neutrality

T-1. *Electric Vehicles Favored Over Renewable Natural Gas*

T-1.1. Comment: Natural gas has helped the LCFS program achieve significant greenhouse gas emission reduction as fossil natural gas and will continue to do so as renewable natural gas. New provisions in the draft LCFS regulatory amendment language to the LCFS will impede the growth of RNG production and the advancement of the natural gas industry as a whole. The LCFS is was built on a concept of fuel neutrality with the ultimate goal of reducing the carbon intensity of California's transportation sector fuels. Instead of promoting the fuel and technology neutral concept, the draft amendments appear to provide inequitable regulatory advantages to electric vehicle (EV) applications at the expense of other low carbon fuels, especially RNG. Such built-in inequalities will affect the integrity of the LCFS program and can jeopardize the future availability of low carbon fuel to California. (SCG1_75-5)

> **Agency Response:** Staff agrees with the commenter that renewable natural gas will continue to achieve greenhouse gas emission reductions with the support of the LCFS, and believes that any perceived barriers to growth in RNG and advancement of the natural gas industry are necessary to ensure accuracy in quantifying reductions and to preserve the environmental integrity of the program.

T-1.2. Comment: Further, EV credit generators using the California grid mix pathway are likely over-generating actual values as it is does not appear that since the LCFS program does not accounts for time of use of EV charging. Renewable [*sic*] While it is true that renewable energy represents an increasing share of the California grid mix, however these renewable sources are in short supply during peak hours when the majority of EV charging occurs meaning that most EVs are charging with non-renewable and more carbon intense electricity than otherwise reported. The fact that EVs are likely over-generating environmental value and biofuels will be under-generating environmental value is again a competitive advantage for EVs that should not and cannot be allowed in under the a fuel neutral LCFS Program. (SCG1_75-12)

> **Agency Response:** Staff acknowledges that determining hourly grid carbon intensities and requiring hourly reporting would improve accuracy in quantifying GHG reductions from EV charging. However, data challenges prevent staff from adopting this approach today across all EVs. Instead, staff has developed a proposed table of smart charging carbon intensities to enable those who do collect hourly charging data to more accurately report EV charging on a voluntary basis, and to further incent this level of data collection and monitoring. This approach also creates an incentive for shifting charging to periods of time when the grid has more renewable supply. Staff is not aware of any evidence to support the assertion that most EVs are charging with more carbon intense electricity than reported.

T-2. Multiple Comments: *Maintain Fuel Neutrality*

Comment: The LCFS is one of the most flexible, fuel-neutral, performance-based standards in the world. We commend the California Air Resources Board for its foresight in establishing a standard based on lifecycle emissions. This approach ensures that the program is grounded in science and that the market will compete to provide the lowest carbon fuels at the lowest cost. As noted above, the LCFS approach has successfully promoted innovation and investment in a wide range of low carbon alternative transportation fuels, including ethanol, biodiesel, renewable diesel, conventional and renewable natural gas, and electricity. Fuel neutrality has allowed the LCFS to adapt flexibly to changes in fuel markets and to the evolving science of the lifecycle emissions of different fuels. As such, the policy can expand to include new fuels and fuel pathways provided that they meet the same high standards of science-based, life-cycle analysis and detailed reporting that have been critical to its success to date, and that crediting is based on actual transportation fuel use rather than on fueling infrastructure capacity. (COALITION1_107-2)

Comment: The LCFS program was designed to be fuel-neutral and to promote the use of alternatives to diesel and gasoline. Those fuels only make up 20% of the fuel used in California's transportation sector, so we must continue to support all low carbon fuels in order to meet our ambitious goals and provide the air quality that we all deserve. (CNGVC1_118-3)

Comment: One is the fuel neutrality of the program. We think it's important. We think that it creates an opportunity for a lot of different fuels to participate in helping California meet its goals, and we should definitely guard that as much as we possibly can. (CNGVC2_T32-2)

> **Agency Response:** The infrastructure crediting proposal is responsive to the Governor's Executive Order 8-48-18, direction in Board Resolution 18-17, and stakeholder comments. This amendment is intended to support development of ZEV infrastructure and is designed to sunset after an initial period of enhanced support for ZEV infrastructure build-out. The maximum quantity of infrastructure credits issued will be capped at 2.5 percent of overall program deficits for each category (2.5 percent for the hydrogen station provision and 2.5 percent for the fast charging provisions, for a maximum of 5 percent of total deficits across both). The LCFS has provided, and will continue to provide, strong incentives for all alternatives to diesel and gasoline. Staff does not believe that the infrastructure proposal negatively impacts the LCFS benefits provided to other low carbon fuels relative to the status quo.

T-3. *Infrastructure Crediting*

T-3.1. Comment: Since its inception, the LCFS has been promoted as a performance-based standard that is technology neutral. RFA is concerned that certain proposed amendments potentially undermine the program's technology neutral design. Specifically, CARB is proposing to allow a credit accounting framework that assumes

electricity used for electric vehicle (EV) charging and hydrogen production came from renewable power generation, even if there is no direct linkage of the EV charging or hydrogen production system to renewable power generation systems. CARB states that it is allowing this unique indirect accounting benefit to "promote the expansion of zero-emission vehicle infrastructure" because, to date, "we have seen very little interest in such pathways under the current rule."[1]

1 ISOR, at EX-5.

Meanwhile, biofuel producers are not allowed to claim credit for reducing the carbon intensity of biofuel processing through the purchase and indirect use of biogas injected into common carrier pipelines or renewable electricity put onto the grid, even if the producer is able to present documentation verifying the purchase of biogas or renewable electricity. Thus, ethanol producers have very little incentive under the LCFS to stimulate the use of biogas or renewable electricity as process energy sources unless they can generate the energy onsite, which is rarely feasible from a technology or economic standpoint.

RFA believes these proposed amendments potentially undercut the technology neutrality principles of the LCFS program, inevitably resulting in the picking of technology "winners and losers." We strongly recommend that if indirect accounting is allowed for renewable energy use in EV and hydrogen pathways, then indirect accounting should also be available for biofuel producers who can present evidence that they have purchased renewable electricity or biogas transmitted through the grid or common carrier pipeline.

…

Changes Needed to Allow Greater Flexibility and Ensure LCFS is Technology Neutral

According to the study, the LCFS cannot be truly technology-neutral until changes are undertaken to allow the sale of higher ethanol blends, which provides more compliance flexibility and lower cost.

- *"Importantly, different ethanol blend levels and vehicle technologies are not mutually exclusive and the technology-neutral structure of the LCFS is intended to allow the marketplace to determine the economically optimal mix of fuels that achieves compliance."*

- *"However, the LCFS cannot truly act as a technology-neutral program unless and until higher levels of ethanol are allowed in the gasoline pool."* (RFA1_80-4)

  Agency Response: Infrastructure development for the use of liquid hydrocarbons in vehicles has been actively supported since the early 1900s. As liquid-hydrocarbon dispensing stations have been developed and deployed, costs have come down which has led to the technology lock-in and dominance that exists today for liquid hydrocarbons. The LCFS program's objective is to incentivize the development of low carbon fuels and their deployment in California. This will require substantial technological development alongside

deployment of less mature technologies, such as EV charging stations or hydrogen fueling stations. None of the statutes and laws that govern the LCFS necessitate LCFS's fuel neutrality. The proposed infrastructure credits provisions will bolster the investment in ZEV refueling infrastructure which will help achieve both the LCFS program's main objectives, and will further align the LCFS program objectives with the wider State's goals of increasing the rate of ZEV adoption in California while driving down the costs of this technology.

Electric Vehicle Charging and Hydrogen Refueling are substantially different processes compared to conventional fuel production and current biofuel production processes from existing facilities. Electric Vehicle charging often occurs in urban areas with limited land-area footprints for on-site renewable generation. Allowing off-site renewable electricity generation to be contracted for use at large-scale chemical production facilities is not comparable to EV charging given that industrial chemical plants are often located away from urban areas and have substantially larger land-use footprints, compared to charging stations, which makes on-site integration of low-carbon electricity viable for these chemical pathways. Given the land area available to larger production facilities, the LCFS will continue to require behind-the-meter renewable electricity demonstration for most fuel pathways to assure that the renewable load is correctly being matched and adequately integrated into the production facility's process for fuel production.

The commenter also recommends consideration of higher ethanol blends. Please see the response to GROWTHENERGY1_B4-51 in the Response to Comments on the Draft Environmental Analysis of the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

T-3.2. Comment: The prospects for electric drive are strong, but still uncertain: they clearly merit continued and expanded LCFS crediting, but do not call for re-focusing low-carbon fuels policy preferentially on electricity rather than continuing to promote a wide range of low-CI alternatives through the LCFS.

But the design and implementation challenges of promoting electric drive through the LCFS while maintaining neutrality are substantial. For light-duty vehicles, where technical prospects are strongest and growth is fastest, LCFS incentives are hard to target effectively. The present targeting of LCFS electric credits on EV purchase decisions is sensible, since these drive production growth and cost reductions, but LCFS incentives can target only some of the associated barriers and are relatively weak. For the subsequent factors determining emissions – how much EVs are driven, and the CI of charging electricity – the targeting of LCFS incentives is weak. After vehicle purchase, most residential charging is not separately metered so LCFS credits must rely on weak proxies for actual vehicle use, although these can be improved with better charging data, via separate meters or direct collection from vehicles. The challenges of heavy transport are the reverse of those for light-duty vehicles. Technical challenges to electrification are greater, but separate charging improves the targeting of incentives from LCFS credits, while heavy commercial usage makes them more

valuable. Additional CI reductions for any electrified transport modes will also depend on the mix of electrical generating sources. As an end-use-oriented policy in the integrated electrical grid, the LCFS will have limited ability to influence these decisions. They will require other policies to promote continued electrical decarbonization and electric-transport interactions, such as role of vehicle charging in energy storage and load management. (UCLA1_B8-1)

> **Agency Response:** The LCFS program provides incentives for all low-carbon fuels and, therefore, staff disagrees with the suggestion that the program is focusing low-carbon fuels policy preferentially on electricity rather than continuing to promote a wide range of low-CI alternatives through the LCFS. While the amendments do include additional crediting for hydrogen and fast charging infrastructure, as well as flexibility for matching low-CI electricity to EV charging and hydrogen production through electrolysis, these credit generating mechanisms make up a small fraction of the credits necessary for program compliance. Credits generated through use of biofuels will continue to be the dominant mechanism for compliance with the standard.
>
> Staff agrees with the comment that targeting LCFS credit generated through electric vehicle charging on EV purchase is appropriate. In response to Board direction, staff worked with a diverse group of stakeholders including utilities and automakers to facilitate a statewide rebate program that would streamline the LCFS incentives by creating a standard point-of-purchase rebate available for all EV buyers across California. Staff believes this change would further promote plug-in electric vehicles with greater all-electric range and larger battery packs, so the incentive can help advance battery technology in-line with the technology advancement goals of the LCFS and support the state's ZEV adoption and emission reduction targets.
>
> Staff also agrees with the commenter's suggestion that the targeting of LCFS incentives in the residential charging sector can be improved with better charging data. Amendments to promote the use of low-CI electricity in residential charging will give preference to entities that can provide metered data through in-home charging equipment or vehicle telematics. Entities desiring to claim credits for smart charging in residences will also be required to provide metered data.
>
> Finally, although staff agrees with the commenter that other policies beyond the LCFS are needed to promote electrical decarbonization and electric-transport interactions, the adoption of amendments to promote the use of low-CI electricity beyond that required for RPS compliance and smart charging will help with meeting these broader goals.

T-3.3. Multiple Comments: *Technology Neutrality*

Comment: Technology neutrality of this program in particular has allowed it to withstand some political and outside pressures. I'd like to encourage your continued vigilance of the technology neutrality of the LCFS. Other jurisdictions, including the

midwest, are considering their own programs or could be considering them sometime soon. And as political times change for us in California, the guiding principle of technology neutrality can allow the program to continue to thrive. (AJWIOGEN2_T2-1)

Comment: I would like to kind of piggyback on the last commenter and her note on technology neutrality. We believe that it's very important for this body to ensure that the technology-neutral focus of the program is maintained. (RFA2_T3-3)

Comment: Having said that, we do have a couple of concerns that remain in the proposed changes as they relate to biofuels. And I just want to remind the Air Board, biofuels currently provide more than 90 percent of all of the low-carbon fuels under this program. More than 90 percent. And even with the Governor's executive order on zero-emission vehicles, which I think we all support, it calls for 5 million ZEVs in 2030. That leaves 25 million other vehicles on the road twelve years from now, and it will be tens of millions for a long period after that. Biofuels are what we can do now and in the next decade or two to reduce air pollution and greenhouse gas emissions from the five-sixths of the vehicles that will still be on the road in 2030 and beyond.

Biomethane in particular is also critical to reduce short-lived climate pollutants including those from dairies and from diverted organic waste and agricultural and forest waste that would otherwise be burned.

Biofuels are also the fifth largest component of the 2030 scoping plan. They are a critical component of the State's plan to achieve its 2030 climate goals.

So given all that, it is very important to remain technology and fuel neutral in the Low Carbon Fuel Standard; (BAC2_T4-1)

Comment: Also would like to flag the importance of fuel neutrality in this regulation. And would note that if the EV sector is going to have access to indirect renewable credits, that in fact that might be something the other fuels should have access to as well. It would be both beneficial to the doability of the regulation and also good for the environment. (PE1_T42-3)

> **Agency Response:** Staff generally agree with commenters' suggestion that general technology and fuel neutrality has been and will continue to be an important design element of the LCFS. The LCFS program's primary objective is to reduce the average carbon intensity of transportation fuel by incentivizing the development of low carbon fuels and their deployment in California. Please see response to I-3.1 Multiple Comments: *Departure from Fuel Neutral Approach and would not Represent Actual GHG Emission Reductions* in Chapter V for a summary explanation of the authority, direction, and rationale supporting the proposed ZEV infrastructure provisions and associated limited departure from fuel/technology neutrality.

U. Rulemaking Procedure

U-1. Multiple Comments: *Support for the LCFS Rulemaking Procedure*

Comment: We appreciate the time and energy CARB staff have committed to this rulemaking process over the past few years. We are appreciate the countless public workshops and discussion we have had with CARB staff. We are hopeful that this updated rule-making will continue to set the standard for all other low carbon/clean fuel policies around the world. (REG1_88-1)

Comment: NextGen would again like to commend CARB and the LCFS Program Staff on their extensive series of workshops, strong analysis and openness to constructive discussion throughout the LCFS rulemaking process. (NEXTGEN1_124-22)

Comment: …thanks staff and Board for your exhaustive and extensive stakeholder process on this rule; (EIN2_T30-1b)

Comment: We commend staff for its great work and willingness to answer a lot of questions and be very thoughtful and diligent about incorporating feedback into the plan. So thank, Floyd, Sam, and Jim and team. (CALSTART2_T13-1b)

> **Agency Response:** Staff appreciates the commenters' support for the rulemaking process and staff's efforts.

U-2. Multiple Comments: *Review Period*

Comment: The only workshop draft regulatory language was held on September 22, 2017 and comments on this and the regulatory language, which was released only a few days prior, are due on October 6, 2017. Two weeks is not a sufficient timeframe for stakeholders to properly comment on both the draft amendment language and the workshop. This is a major initiative that greatly impacts the natural gas and other fuel industries. There have been considerable changes made in the draft language that will require detailed review by stakeholders and the expedited process set by that ARB does not allow this to happen. Additionally, comments on the draft concepts were due on September 5, 2017, which was followed a little more than two weeks by the workshop. It begs the question whether comments on the concepts were read and considered in preparing the draft language. (SCG1_75-3)

Comment: Furthermore, ARB has yet to release a full version of their modified GREET 3.0 for stakeholder review. Many of the important changes in the regulation are based on GREET 3.0 assumptions, therefore, GREET 3.0 should be released in its entirety and adequate time must be allotted for stakeholder review prior to making changes in the regulation. Stakeholders are unable to substantively comment on the technical merits of the regulatory changes without reviewing the changes to GREET 3.0.

We request that the GREET 3.0 model be released for public review and comment as soon as possible. We also request that the LCFS regulatory process be suspended until GREET 3.0 is reviewed and finalized. (SCG1_75-4)

Agency Response: Staff notes that the comments are from a feedback letter dated October 6, 2017 (during the pre-regulatory or informal rulemaking phase) that was submitted as an attachment to the formal comment letter submitted to the rulemaking docket April 28, 2018. The formal rulemaking phase is initiated by the release of the Notice of Public Hearing and the Staff Report (ISOR), which occurred on March 6, 2018, and was followed by the 45-day public comment period.

The public process conducted in development of the LCFS amendments was complete, extensive, and robust. During the pre-regulatory phase, staff held 22 public workshops and working meetings, as enumerated in the ISOR, Chapter XI, Table XI-1. The commenter points to a single draft and workshop of regulatory language that occurred in the pre-regulatory phase, yet staff notes there is no requirement to release such text prior to the formal rulemaking phase. During the formal rulemaking period stakeholders have multiple opportunities to review and comment on the proposed regulatory language. As part of this public process, staff met with all stakeholder groups, including the commenter, upon request.

The commenter questions whether the feedback received prior to September 5, 2017 were read and considered prior to the September 22, 2017 public workshop. Staff would like to assure the commenter that all letters received, before or after "due dates" are read and considered by the relevant staff. Staff routinely requests feedback by a given date, but generally accepts feedback at any time and is always available for individual meetings and teleconferences with stakeholders.

During the April 4, 2017 public meeting, staff first announced that CA-GREET3.0 would be based on the publicly-available GREET 1 2016 model developed by Argonne National Laboratory. The first draft of CA-GREET3.0 was then released for public review during the pre-regulatory phase, on August 7, 2017. Revisions were adopted in response to stakeholder feedback received on that initial draft, and an updated version was posted on November 6, 2017. With the start of the rulemaking on March 6, 2018, staff's proposal included the CA-GREET3.0 model along with the five Tier 1 Simplified CI Calculators that were proposed to be incorporated into the regulation, and the public had 45 days to review and submit comments. Subsequently, and in response to public comments, staff released model and calculator updates and three additional Tier 1 Simplified CI Calculators with the first and second Notice of Public Availability of Modified Text on June 20, 2018 and August 1, 2018, which were each followed by 15-day public comment periods.

U-3. *Peer Review*

Comment: The Health & Safety Code provides that CARB shall not "take any action to adopt the final version of a rule unless" it undertakes a peer review to evaluate the "scientific portions" of the rule. (Health & Saf. Code, § 57004(d).) Section 57004

requires that: (1) CARB "submit[] the scientific portions of the proposed rule, along with a statement of the scientific findings, conclusions, and assumptions on which the scientific portions of the proposed rule are based and the supporting scientific data, studies, and other appropriate materials, to the external scientific peer review entity for its evaluation," and (2) the peer reviewer "prepare[] a written report that contains an evaluation of the scientific basis of the proposed rule." (*Id.*, subd. (d).) Section 57004 of the Health and Safety Code defines the "scientific portions" of a proposed rule to include "those foundations of a rule that are premised upon, or derived from, empirical data or other scientific findings, conclusions, or assumptions establishing a regulatory level, standard, or other requirement for the protection of public health or the environment." (*Id.*, subd. (a)(2).)

Numerous aspects of the proposed amendments "are premised upon, or derived from, empirical data or other scientific findings, conclusions, or assumptions establishing a regulatory level, standard, or other requirement for the protection of public health or the environment." (*Id.*, subd. (a)(2).) These "scientific portions" include, but are not limited to:

- The accuracy of each of the components of CA-GREET 3.0, and the effect on the CI for corn ethanol and sugarcane ethanol;
- The ILUC for corn ethanol;
- The EER for electricity;
- The efficacy of NTDEs to reduce NOx emissions from biodiesel;
- The accuracy of CARB's compliance scenario, including but not limited to the adaptation of alternative jet fuels, solar steam projects, and renewable diesel, and
- The potential impacts associated with CARB's compliance scenario not coming to fruition, particularly with respect to alternative jet fuels, solar steam projects, and renewable diesel.

It is unclear whether CARB has sought external peer review to evaluate the scientific portions of the rule, consistent with Section 57004. As such, the subject of any such peer review is unknown. If CARB has not sought peer review under Section 57004, Growth Energy requests an explanation of the reason why none was sought and completed. (GROWTHENERGY1_B4-32)

> **Agency Response:** For an explanation of the peer review process supporting the fundamental scientific bases of the health protective standards and methodological framework underlying the LCFS and ADF, please see the response to comment GROWTHENERGY1_B4-17 in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations. The specific scientific foundations of the LCFS are the general methodologies for calculating life cycle carbon intensity values of transportation fuels, crude oil supplied to

California refineries, and indirect land use change of crop-based biofuels. The specific scientific foundations of the ADF are the multimedia evaluations of biodiesel and renewable diesel. Although commenter is correct that many aspects of the LCFS and ADF are based upon important ongoing technical and scientific work, Health and Safety Code section 57004 requires peer review of the "foundations" of such rules, and such peer review of those foundations was conducted in connection with the 2015 LCFS and ADF rulemaking.

U-4. *Requirements of Transparency*

Comment: Growth Energy has substantial concerns about the completeness of the rulemaking file for the proposed amendments, as it did in the prior rulemakings. The Court of Appeal made clear in *POET v. CARB* that neglect to include even a limited number of relevant documents in the rulemaking file would violate the Government Code.

As such, Growth Energy urges CARB to maintain a full and complete rulemaking file, and to make that file available for public review. Among other things:

- The rulemaking file must include external communications submitted to the staff, the Executive Officer or the Board prior to the date when the rulemaking file is formally opened must be included in the rulemaking file. If those communications are not included, it should explained why.
- Growth Energy urges CARB to take all necessary measure to ensure all external submittals (not within the scope of section 11347.3(b)(7)) concerning this regulatory process have been included in the rulemaking file.
- Growth Energy also urges CARB to ensure all factual information relied upon by CARB staff in connection with the consideration of the Proposed Amendments is included in the rulemaking file. (GROWTHENERGY1_B4-34)

Agency Response: Please see the response to GROWTHENERGY1_B4-16 Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations. The commenter's assertion that "The rulemaking file <u>must include external communications</u> submitted … <u>prior to the date when the rulemaking file is formally opened</u>" (emphasis added) is inaccurate. The relevant authority, Government Code section 11347.3, actually specifies that a rulemaking file shall include, among other things, "written comments submitted to the agency in connection with" the rulemaking action. The rulemaking file for this regulatory amendment proceeding does include such comments.

V. Analysis of Alternatives

V-1. Multiple Comments: *E15 and Higher Ethanol Blends*

Comment: Advantages of and Market Access for High Ethanol, High Octane Fuel

Finally, while we recognize restrictions on higher ethanol blends are also outside the scope of this rulemaking, ACE members believe CARB needs to consider unlocking additional GHG benefits and accelerating compliance with the LCFS by allowing market access to blends of ethanol beyond E10 in the state.

As stated above, ethanol delivers better lifecycle GHG emission benefits than CARB assumes from its current modeling approach. But ethanol's benefits are not limited to GHG reductions. Ethanol is also a superior low carbon source of high octane fuel which can help automakers meet tailpipe emission and fuel economy standards. We urge CARB to consider the far-reaching low carbon high octane advantages higher ethanol blends could provide in helping the state fulfill LCFS implementation and broader goals to reduce petroleum use and reduce emissions.

In fact, Argonne scientists recently found the use of E25 and E40 reduce well-to-wheel GHG emissions by 4 and 8 percent, respectively, relative to E10 gasoline (which is the highest ethanol-gasoline blend currently allowed in California beyond E85). When Argonne added the full lifecycle GHG benefits of the higher ethanol levels with the well-to-wheel reductions, the use of E25 and E40 reduced total emissions by 8 and 17 percent, respectively. Argonne concluded, "The analysis shows that ethanol can be a major enabler in producing high octane fuel and E25 and E40 can result in additional reductions in well-to-wheel GHG emissions compared to regular E10 gasoline."[5]

[5] Well to Wheel Greenhouse Gas Emission Analysis of High Octane Fuels with Ethanol Blending. Argonne National Laboratory. Jeongwoo Han, Michael Wang, and Amgad Elgowainy. August 2016

In partnership with their colleagues at the Oak Ridge National Laboratory and National Renewable Energy Laboratory, Argonne scientists also released the Summary of High Octane, Mid-level Ethanol Blends Study in July 2016.[6] This comprehensive paper examined the GHG emission benefits of high octane mid-level ethanol blends, knock-resistance and ethanol blends, the economics of ethanol, and marketplace issues such as retail and terminal infrastructure. "The experimental and analytical results of this study considered together show that high octane fuel, specifically mid-level ethanol blends (E25-E40), could offer significant benefits for the United States. These benefits include an improvement in vehicle fuel efficiency in vehicles designed and dedicated to use the increased octane. The improved efficiency of 5-10 percent could offset the lower energy density of the increased ethanol content, resulting in volumetric fuel economy parity of E25-E40 blends with E10. Furthermore, dedicated high octane fuel vehicles would provide lower well-to-wheel GHG emissions from a combination of improved vehicle efficiency and increased use of ethanol. If ethanol were produced using cellulosic sources, GHG emission would be expected to be 17 to 30 percent lower than those from E10 using conventional ethanol and gasoline. Analysis of the high octane fuel market and the primary stakeholders reveals that the automotive OEMs,

consumers, fuels retailers, and ethanol producers all stand to benefit to varying degrees as high octane fuel increases its market share. The results depend on the underlying assumptions; but high octane fuel offers an opportunity for improved fuel economy, and these dedicated vehicles are likely to be appealing to consumers."

[6] Summary of High-Octane, Mid-level Ethanol Blends Study. July 2016. ORNL, NREL, ANL. U.S. Department of Energy. http://info.ornl.gov/sites/publications/files/Pub61169.pdf

As California and EPA continue a dialogue about future vehicle emission and fuel economy standards, we encourage consideration for the role high ethanol blends can play in helping automakers meet those standards. (ACE1_41-10)

Comment: CARB Staff Should Consider Alternative Fuel Specifications for E15 In Order to Facilitate Compliance with the LCFS Regulation

In 2010[1] and 2011[2], the U.S. EPA promulgated partial waivers allowing the use of E15 in 2001 and newer model-year vehicles. E15 is now available in 29 states.[3] However, at present, California has not adopted the alternative fuel specifications required to allow for the sale of E15 in the state despite the fact that CARB has long recognized that E15 can play an important part in reducing GHG emissions and ensuring that transportation fuel providers can comply with the LCFS regulation. This is the case, for example, in the ISOR for the 2009 LCFS regulation[4] where staff noted that E15, if approved by U.S. EPA, could provide additional volumes of ethanol needed for LCFS compliance. Similarly, in 2011, after U.S. EPA's approval of E15, the LCFS Advisory Panel's assessment of the potential for future compliance with the LCFS relied heavily on an assumption that E15 would be in widespread use in California by 2016.[5]

[1] https://www.gpo.gov/fdsys/pkg/FR-2010-11-04/pdf/2010-27432.pdf
[2] https://www.gpo.gov/fdsys/pkg/FR-2011-01-26/pdf/2011-1646.pdf
[3] http://www.afdc.energy.gov/fuels/ethanol_e15.html
[4] See page VIII-13 of https://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor1.pdf
[5] https://www.arb.ca.gov/fuels/lcfs/workgroups/advisorypanel/20111208_LCFS%20program%20review%20report_final.pdf

Further, as indicated in CARB's "Illustrative Compliance Scenario Calculation"[6], CARB staff currently estimates that the use of ethanol results in approximately 30% less GHG emissions than the use of a comparable amount of petroleum based gasoline feedstock based on equivalent energy content and forecasts that by 2030, GHG emissions from ethanol use will be 50% lower than from petroleum feedstocks. Given this, it is clear that allowing E15 in California will reduce GHG emissions, and result in greater volumes of LCFS credits which in turn will help to ensure and reduce the cost of LCFS compliance. E15 fuel specifications would also further diversity California's transportation fuel pool and reduce California's reliance on CARB staff's postulations regarding the availability of new supplies of renewable diesel, biodiesel, and electricity in order to achieve LCFS compliance.

[6] https://www.arb.ca.gov/fuels/lcfs/rulemakingdocs.htm

While CARB has not yet moved forward to enact specifications for E15, it is clear from the U.S. EPA's action that there are no technical barriers to the use of E15 in California in 2001 and later model-year vehicles that constitute the bulk of the California vehicle

fleet. It is also evident that widespread use of E15 would increase the already large of amount of LCFS being generated by ethanol[7] by another 50%.

[7] See for example, page I-6 of the 2018 LCFS ISOR.

Give the above, CARB would either move forward as quickly as possible to initiate the rulemaking process required to develop California fuel specifications for E15 or provide an analysis that shows the technical, environmental, and/or economic reasons why E15 should not be available in California to assist fuel providers in complying with the LCFS regulation. (GROWTHENERGY1_B4-67).

Comment: C. Amend current regulations to allow the sale of E15 (15% blends in California

Current state regulations preclude the sale of E15 in California, despite the facts that 1) the fuel has been legally registered at the federal level since 2011; 2) E15 is currently sold in 30 other states; and 3) more than 90% of the existing light-duty automotive fleet is legally approved to consume E15.

A recent study by Life Cycle Associates (summarized in Attachment B) shows that the introduction of E15 would significantly increase credit generation, reduce gasoline consumption, and enhance the near- and long-term sustainability of the LCFS.[4] If California allows the sale of E15 beginning in 2020, the study shows cumulative GHG reductions achieved under the LCFS increase by 15-19 MMT CO2e by 2030, depending on the mix of ethanol sources.

[4] The January 2018 Life Cycle Associates study, previously shared with CARB staff, examined scenarios based on a 2020 CI reduction benchmark of 10% and a 2030 CI reduction benchmark of 18%, as discussed during the 2017 stakeholder process. While the CI benchmark curve proposed in the ISOR leads to slightly different credit/deficit results than those presented in the Life Cycle Associates study, the GHG reductions achieved under the study's E15, high octane fuel, and E85 PHEV scenarios remain valid directionally and in terms of magnitude.

…

By the state's own assessment, full penetration of zero emissions vehicles – while progressing – is still decades away. We believe that biofuels like ethanol can help further decarbonize the use of the remaining passenger cars and light-duty trucks still using internal combustion engines as the state continues to increase adoption of zero emission vehicles. For example, use of fuels containing higher levels of high-octane ethanol in the state's growing fleet of hybrid vehicles could cut the greenhouse gas (GHG) emissions of those automobiles by 50% or more.

For that to happen, however, the state should better encourage the use of low-cost, consumer-friendly climate solutions that are commercially ready today, like higher ethanol blends. We ask that you support efforts to maximize the use of low-carbon liquid fuels in vehicles with internal combustion engines. Specifically, we seek your help in convening discussions that bring together biofuel producers, automakers, and ARB staff to identify options for decarbonizing the remaining liquid transportation fuel used in the state.

There are a range of solutions that could provide low-cost access to lower-carbon fuel options in the existing internal combustion engine fleet. Collaboration with the auto sector is necessary to enable fuel choices above and beyond gasoline blended with 10% ethanol (E10), which is the highest level of ethanol currently allowed for use in conventional automobiles by California regulations. We have had initial conversations with ARB staff regarding regulatory changes that may be necessary to allow expanded use of commercial-ready low-carbon liquid fuel solutions, like higher ethanol blends (15% ethanol and more), and we look forward to more expansive regular dialog on these issues.

We believe that efforts to further decarbonize liquid fuels are entirely consistent with California's leadership in climate solutions. It is reasonable to expect that other states may not adopt zero emission vehicles at the same rate as California. However, by increasing the use of low-carbon liquid fuels, California will not only accelerate its own GHG emission reduction efforts, but it will also add to the menu of decarbonizing options that other states might consider adopting based on California's example.

…

Approval of E15 Would Generate 15-19 MMT of Additional GHG Reductions by 2030

The study shows that introduction of E15 would significantly increase credit generation, reduce gas consumption, and enhance near- and long-term sustainability of the LCFS. If California allows the sale of E15 beginning in 2020, the cumulative GHG reductions achieved under the LCFS increase by **15-19 MMT CO2e by 2030**, depending on the mix of ethanol sources.

E15 Helps Avert Near-Term Credit Bank Depletion

In the study's E15 cases, the phase-in of E15 increases credit generation in the near-term and allows the credit bank to avoid exhaustion in 2021. The bank grows even more over time as E15 more fully penetrates the market, potentially setting up the LCFS to deliver CI reductions beyond 18% in 2030.

- *"Adoption of E15 beginning in 2020 helps avert complete exhaustion of the LCFS credit bankand ensures the bank remains positive in the near term."*
- *"E15 is a helpful near-term option with growing CI benefits for decades."*

…

- If California allows the sale of E15 beginning in 2020, it would increase the cumulative GHG reductions achieved under the LCFS by approximately **15-19 million MT CO2e by 2030**,depending on the mix of ethanol sources used to make E15. This is roughly equivalent to the *total* number of credits generated by *all* gasoline and diesel replacement fuels in the first five years of the LCFS program (2011-2015). (RFA1_80-1b)

Comment: We fully understand the Board's commitment to zero-emission vehicles. But as California progresses in that direction, we believe ethanol can contribute to further decarbonization of the remaining use of liquid combustion fuels. Higher ethanol blends beyond today's norm of 10 percent could significantly reduce GHG emissions from the liquid fuels pool, while reducing petroleum consumption.

One analysis that we've provided to ARB staff shows that even a modest increase in the ethanol blend level could provide an additional 15 to 19 million metric tons of CO2 reduction cumulatively by 2030.

But significant volumes of low CI ethanol are being left out of the California market due to various regulatory barriers, leaving California motorists with few options at the pump other than gasoline. So we're asking for the opportunity to continue working with your staff to bring together appropriate stakeholders in discussions aimed at identifying options for decarbonizing the remaining use of liquid combustion fuels in California. (RFA2_T3-2).

Comment: Lastly, echo the comments of Geoff Cooper of the RFA in terms of the ability of the ethanol sector as it continues to lower the CI to dramatically bring reduced tons of CO with further access to the market. (PE1_T42-4)

> **Agency Response:** Please see the response to comment GROWTHENERGY1_B4-51 in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

V-2. *Western States Petroleum Association Alternative*

Comment: *The WSPA Alternative.* WSPA submitted a proposed alternative in response to CARB's solicitations of alternatives. The WSPA Alternative contemplates that GHG emissions currently attributable to the LCFS program would "instead be achieved by the Assembly Bill (AB) 32 Cap and Trade program in the most cost-effective manner to address GHG emissions." (EA at 207; see also ISOR at IX-1.) This proposal would be "paired with incentive to foster innovation." (ISOR IX-1.) The ISOR, however, rejected this alternative, and declined to further analyze it, "because it is less likely to accomplish the innovation and fuel substituting benefits intended by the LCFS," (ISOR at IX-1–IX-2), and because CARB had not "been appropriated funding for such incentives" (*Id.* at IX-2). The WSPA Alternative would also minimize leakage by avoiding "fuel shuffling." (See *supra,* § IV. B. 3.) By failing to consider the WSPA Alternative, the ISOR does not comply with the Government Code. First, the issue under Section 11346.5(a)(13) is not whether a proposed alternative meets each and every project objective articulated by an agency for a regulation. Rather, Section 11346.5(a)(13) requires CARB to evaluate whether the alternative would be "equally effective in implementing the statutory purpose…." Here, the statutory purpose is ***not*** fostering innovation in fuel, (*cf.* ISOR at IX-2), but rather ensuring GHG emissions will be "reduced to at least 40 percent below the statewide greenhouse gas emissions limit not later than December 31, 2030," in a manner that is technologically feasible and

cost-effective. (Health & Saf. Code, § 38566.) As such, "innovation" cannot be a proper basis to reject an alternative under Section 11346.5(a)(13).

In any event, the WSPA Alternative will spur innovation. Indeed, WSPA's strategy to use financial incentives to promote innovation is the same strategy that CARB itself has used to achieve the same goals. (Appendix A, Attachment 2.)

The WSPA Alternative would also be effective in achieving reduced emissions required under SB 32. As previously recognized by CARB when Growth Energy proposed a similar alternative in 2015, cap-and-trade alternative would "likely" achieve the same "estimated GHG emissions reductions" as the LCFS regulation during the relevant period. (2015 ISOR (LCFS), Appx. F at 26-27.) There is no evidence or analysis to suggest the WSPA Alternative would not be equally efficacious. It should also be noted that a demonstration that there are no superior alternatives to a proposed regulations, as required under Section 11346.9(a)(4), must be based on "supporting information." To date, however, there is no such "supporting information" in the rulemaking file of which Growth Energy is aware. If the Board intends to add such information to the rulemaking file in order to carry its burden under Section 111346.9(a)(4), it must comply with sections 11347.1 of the Government Code. (GROWTHENERGY1_B4-29)

> **Agency response:** Please see the response to comment GROWTHENERGY1_B4-50 in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

V-3. *Analysis Alternatives under the Government Code*

V-3.1. Comment: There is no question that the Proposed Amendments will affect "private persons." CARB staff estimates the Proposed Amendments would cause customer fuels prices to rise significantly (up to $0.36/gallon for gasoline and up to $0.44/gallon for diesel). (ISOR, Appx. B at 50); a loss of over 25,000 jobs, (*id* at 63); and a 0.1% decline in the GDP. (*Id.* at 68.) As such, there is a burden of demonstrating that no alternative to the Proposed Amendments would be "as effective and less burdensome to affected private persons and equally effective in implementing the statutory purpose or other provision of law." (Govt. Code, § 11346.5, subd. (a)(13).) And before CARB may consider whether to take action on the Proposed Amendments, it would be necessary to demonstrate, with "supporting information," that "no alternative" that the Board has considered "would be more effective and less burdensome to affected private persons than the adopted regulation, or would be more cost effective to affected private persons and equally effective" in meeting the proposal's legislative objective. (*Id.,* § 11346.9, subd. (a)(4).) (GROWTHENERGY1_B4-27)

> **Agency Response:** DOF regulations state that agencies must include "identification of each regulatory alternative for addressing the stated need for the proposed major regulation;" alternatives that do not meet the stated need for the proposed major regulation are not required to be analyzed. (1, CCR § 2002(c)(8)). Additionally, the regulations state that agencies should analyze

"feasible alternatives..." while taking into account "an evaluation of the legal and statutory constraints that limit the selection of regulatory alternatives" 1, CCR § 2003(e)(1)). Section 11342.548 (b)5A provides a description of the alternatives agencies must analyze and Section 11342.548 (b)5C states "an agency is not required to...describe unreasonable alternatives."

Growth Energy, in this comment letter, has suggested that CARB staff should have analyzed two alternatives, which they call the WSPA alternative and the E15 alternative. Staff addresses why the WSPA alternative was not considered in the economic analysis in the Response to GROWTHENERGY1_B4-50 in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations, and why the E15 alternative was not considered in Response V-1 in this chapter.

V-3.2. Comment: CARB's Government Code alternative analysis, located pages IX-1-IX-3 of the ISOR, does substantially discharge CARB's duties under Sections 11346.5 and 11346.9. This section of the ISOR does not itself articulate the "statutory purpose" of the LCFS regulation, or evaluate each alternative against the statutory purpose. For this reason alone, the alternatives analysis is not adequate as an informational document, and does not include the analysis required under Sections 11346.5 and 11346.9. To find the "statutory purpose" of the LCFS, it is necessary to look outside the ISOR and to the text of SB 32. (See ISOR at EX-1, EX-2.) SB 32 states that:

> [i]n adopting rules and regulations to achieve the maximum technologically feasible and cost-effective greenhouse gas emissions reductions authorized by this division, the state board shall ensure than statewide greenhouse gas emissions are reduced to at least 40 percent below the statewide greenhouse gas emissions limit no later than December 31, 2030.

(Health & Saf. Code, § 38566.) Thus, the " statutory purpose" behind the LCFS regulation is to ensure GHG emissions will be "reduced to at least 40 percent below the statewide greenhouse gas emissions limit no later than December 31, 2030," in a manner that is technologically feasible and cost-effective. (*Id.)* The discussion of alternatives likewise falls short of statutory requirements. (GROWTHENERGY1_B4-28)

Agency Response: The LCFS does not cite Health & Safety Code, §38566 as a source of authority, and thus the comment's basis is incorrect. The LCFS program's statutory purpose is derived from the following authority: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, and 43018 Health and Safety Code; 42 U.S.C. section 7545, and Western Oil and Gas Ass'n v. Orange County Air Pollution Control District , 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and Western

Oil and Gas Ass'n v. Orange County Air Pollution Control District, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

W. Miscellaneous

W-1. *Program Linkage with other Jurisdictions*

Comment: Lastly, we would like to reiterate our support to CARB for an integrated LCFS Credit market with Oregon and British Columbia similar to discussions and developments within Cap'N'Trade. (REG1_88-20)

Comment: We also see the other trains that are following California, including in Canada; and we encourage ARB to partner with those jurisdictions to take the next step. (NRDC2_T19-3)

Comment: Continuing enactment of LCFS-like policies in other jurisdictions, as now in place and proposed in several jurisdictions, will bring two types of potential interaction: interactions through linkage of trading systems, and market effects via demand for low-CI fuels. LCFS credit markets can in principle be linked, following the existing model of expanding inter-jurisdictional linkage of cap-and-trade systems. Such linkages can make larger and more liquid credit markets, but would require careful attention to coordination of both administrative trading mechanisms (to avoid double-counting), and policy stringency and design (to avoid arbitrage). Such linkages are not presently feasible due to inconsistent design between the LCFS and other systems now in force and proposed. In particular, other current and proposed LCFS systems exclude indirect land-use change from calculated CI of biofuels, so those systems will generate significantly stronger incentives for production of those biofuels whose CI includes a large iLUC component.

The more immediate interactions will be through effects of increased demand on low-CI fuel markets. Additional LCFS policies, like tightening of California's CI targets, will strengthen incentives for production of low-CI fuels and bid up their prices if production cannot expand apace. The additional policies will also increase incentives for fuel shuffling. Since the new jurisdictions will compete with California for both newly produced and shuffled fuels. But because shuffling is an artifact of CI variation among the initially existing fuel supply mix, shuffled fuels are in fixed supply and will decline in relative importance as demand for low-CI fuels expands. As expansion of LCFS-like policies squeezes out claimed reductions of little merit or future promise, it will also clarify how much of present reductions is coming from shuffling, or from low-CI fuels that are real but also in relatively fixed supply, such as fuels produced from waste oils. As these sources reach their limits, the supply profile of other low-CI fuel options will be revealed more clearly. This will represent an additional source of uncertainty in future credit markets, although the response mechanisms already discussed – the credit clearance mechanism plus ARB's discretion to make small target relaxations under conditions of sustained shortage – are likely to provide adequate ability to respond to these conditions, as they do to uncertainties generated solely within California's credit market. (UCLA1_B8-11)

Comment: In closing, we wish to emphasize the importance of California's role as a global climate policy leader. With its well-developed policy structure, California is

uniquely positioned to provide support and resources to other jurisdictions that are developing climate policy frameworks and evaluating what policies to meet their jurisdiction's needs. California's LCFS is a model policy, variations of which have been replicated or are under consideration in several other subnational and national jurisdictions. We support CARB's work to develop a policy framework that is exportable. Building a regional, national, and international market for low carbon fuels is vitally important to send the right market signals to industry to invest in projects with scale. (COALITION1_107-7)

Comment: *NextGen Supports Linking California's LCFS with Equivalent Programs in Other Jurisdictions*

California's LCFS has become a model for global clean fuels policy. British Columbia and Oregon have already adopted similar programs, Washington State has attempted to do so and the Canadian Federal Government is currently developing a Clean Fuels Program largely based on similar concepts. Several stakeholders have explored the possibility of linking LCFS credit markets, in order to improve liquidity, reduce the risk that fuel producers will relocate fuel-consuming activity into jurisdictions with no fuel carbon policy ("leakage"), and maximize the total market signal to innovative clean fuel producers.

NextGen supports linking California's LCFS with equivalent programs in other jurisdictions, provided that this does not result in a net reduction of aggregate program stringency and that California retains authority to set its own reduction targets.

Linking LCFS credit markets, in a manner analogous to the cap-and-trade program linkages under the Western Climate Initiative can help improve the power and efficiency of the LCFS, while reducing administrative burdens. This is particularly useful for smaller jurisdictions which may lack the capacity to develop and administer a LCFS of their own. Linked markets also reduce the incentive for leakage by encouraging action in other states or regions and reducing the number of uncontrolled jurisdictions to leak to.

We urge Staff to explore opportunities for linkage with other LCFS programs, provided they use equally robust and stringent methods for assessing the carbon intensity of fuels as CARB. We recognize that since California's LCFS targets are significantly ahead of other jurisdictions, since its LCFS has been in effect for far longer, it will be difficult for potential new partners to adopt a LCFS at an equivalent nominal target. Where fuels are credited in jurisdictions other than the one to which they're physically delivered, their credit generation should be assessed relative to the targets in the crediting jurisdiction, rather than the one of delivery.

By allowing some limited flow of credits across borders, linked markets can reduce emissions from the transportation of fuels to market. We urge Staff to seek an appropriate balance between maximizing overall system efficiency and ensuring that

communities in high-demand jurisdictions receive air quality and economic benefits from the fuels used to satisfy their obligation under a linked program. (NEXTGEN1_124-46)

Agency Response: CARB always seeks opportunities to coordinate its policies with, and provide technical assistance to, other jurisdictions that seek to address the climate change problem, since it is a global problem that will require a global solution. To that end, CARB in general conducts regular meetings with other jurisdictions that are implementing or interested in implementing more ambitious GHG emission reduction programs. The LCFS team in particular holds such meetings, for example, with Canada's Clean Fuel Standard team, and with Oregon and British Columbia's clean fuel/LCFS teams as part of the Pacific Coast Collaborative. Staff is open to considering linking the LCFS program with similar programs in the future but acknowledges that the difficulties that the commenters note must be addressed to ensure successful implementation.

Staff agree with the comment that implementing additional policies similar to the LCFS will result in overall increase in the supply of low carbon fuels and diminish the any potential for fuel shuffling over time. Individually, each additional policy independently may, all else equal, increase shuffling to the borders of the implementing jurisdiction. But each additional policy, by increasing the incentive for low carbon fuel consumption within its borders, may reverse existing quantities that are shuffled.

Staff agrees that other jurisdictions will compete for low carbon fuels supply if they implement policies similar to the LCFS, and that this has the potential to increase uncertainty that the LCFS targets are met. However, additional demand from other policies will increase the certainty for existing and potential low carbon fuel producers since the demand for their product is now deep and extensive. As more jurisdictions demand increasing quantities of low carbon fuels, producers will be less apprehensive to invest in new plants and facilities, since demand is not dependent on one jurisdiction where demand may diminish due to an economic downturn or regulatory changes. In summary, staff argues that increased demand from other jurisdictions has the potential to reduce the uncertainty to producers of low carbon fuels, leading to higher investment and innovation in low carbon fuels, which may lead to a more robust supply of low carbon fuel to California as well as other jurisdictions.

Staff acknowledges the commenters' policy recommendations, and staff shares the goal of ensuring the program is exportable and supporting other jurisdictions to adopt programs similar to the LCFS to expand upon the success of the program and prevent "leakage." However, staff notes that these recommendations are not within the scope of this rulemaking because the modifications discussed in the comment were not incorporated in the proposed revisions or included in the notice of changes.

W-2. *Progress Reports*

Comment: It is imperative that ongoing program assessments be conducted, so that appropriate adjustments to the standard can be made in a timely manner should analysis warrant such a change. WSPA recognizes that there will be opportunities to assess progress toward that goal. We encourage ARB staff to maintain their existing progress reporting to the public and the open dialogue with stakeholders that has occurred over the life of the program. (WSPA2_61-13)

> **Agency Response:** Staff appreciates the commenter's suggestion and notes that in addition to the formal progress report to the Board in 2017, staff has also developed the online LCFS Data Dashboard that provides substantial information to the public and market participants on the progress toward achieving the annual CI benchmarks, the total credits and deficits generated and banked, changes in fuel and feedstock use, and more. Staff commits to maintaining existing reporting including the dashboard and credit reports, along with frequent public meetings to explore future regulatory updates with a robust and transparent public process. The annual status report to the Board on Scoping Plan implementation will provide additional opportunities for public input and Board feedback. Finally, pursuant to AB 197, the Board will report annually to the Joint Legislative Committee on Climate Change Policies, ensuring oversight over the implementation of the state's climate policies including the LCFS.

W-3. Multiple Comments: *LCFS Implementation*

Comment: Lastly, given the changes proposed in this rulemaking cycle to the electricity portion of the LCFS program, ChargePoint recommends that ARB develop a streamlined data collection system. With thousands of chargers currently registered in the program, as well as a proposed Time-of-Use (TOU) program that would require hourly data reporting, the current system of emailing Excel files as back-up verification data is neither secure nor efficient. (CHARGEPOINT1_122-8)

Comment: Lastly, related to the comments above on adding fields, we recommend allowing credit transfers to be done via Excel and/or XML file to automate the process and reduce errors. Other programs we transact in allow for trades like this to be uploaded via Excel and/or XML file similar to how fuel transactions can done in LRT currently. However, on credit transfers, we have to manually fill out the form each time we do a transfer which leaves the entire process prone to unacceptable levels of human error. We are not aware of functionality in LRT that would allow for one person to prepare a transfer and another to review it prior to transfer. So while this process has not been too onerous so far due to the limited number of fields, adding additional fields that are not straight forward will lead to mistakes. As you know, even if mistakes are realized quickly, an email is automatically sent to counterparties and credits can be accepted within seconds with those mistakes. We again recommend allowing credit transfers to be done via Excel and/or XML. (REG1_88-19)

Agency Response: Staff appreciates the commenters' suggestion for developing more efficient reporting tools; however, this is not within the current rulemaking scope but is an implementation issue. Staff is committed to continue working with stakeholders in the development of effective and secure tools for LCFS reporting.

W-4. Multiple Comments: ***Not Within Scope of Rulemaking***

Comment: As an ex-banker for 25 years who financed biodiesel plants you may want to do due a lot diligence on the biodiesel companies on your list. Banks have had problems in the past financing biodiesel plants. (Co-bank as an example) In my opinion with RIMS abuse and fraud and RFS in disarray I caution your involvement. I have watched many US biodiesel plants go into bankruptcy and liquidated over the last 10 years. Biodiesel plants (even the biggest 10 years later) have continued to lose money. You can't build a business all based on a tax-credit. It was a flawed plan.

You may want to re-think your plan. (CT1_4-1)

I am not a fan of Big Oil but you may want to consider what Exxon is doing with algae biofuels. Algae is renewable, has no affect on the food channel (like biodiesel) and consumes CO2. (CT1_4-2)

Comment: D. Begin a formal process to consider other pathways for further decarbonizing liquid transportation fuels

While E15 would provide additional low-cost CI reductions in the near term, RFA also believes CARB staff should initiate a more formal dialog with stakeholders—including automakers, fuel producers, fuel retailers, and others—to examine other options for further decarbonizing the remaining liquid fuels in the California market.

Several of these options, including the use of mid-level ethanol blends in high-octane fuel vehicles and the use of E85 flex fuels in plug-in hybrid electric vehicles, could provide substantial GHG reductions under the LCFS. However, certain regulatory and marketplace barriers need to be properly identified and overcome in order for ethanol-based fuels to play an even larger role in transforming the state's liquid fuels pool.

We encourage CARB to work with stakeholders to begin identifying the regulatory and marketplace actions necessary to enable biofuels like ethanol to play a bigger role in decarbonizing California's transportation fuels.

…

High Octane E30 and E85 in Plug-in Hybrids Provide Substantial Longer-Term CI Reduction

The study found that other higher ethanol blend options paired with certain vehicle technologies can deliver even greater CI reductions under the LCFS in the longer term.

- *"High efficiency options such as E30 and E85 plug-in hybrid vehicles (PHEVs) can also support further future CI reductions; however, the time required to roll in vehicles even under rapid commercialization scenarios results in more significant benefits beyond 2030."*
- *"Growth in plug in E85 PHEVs as well as other low CI technologies could support a 20% reduction or more in GHG emissions by 2030."*
- *"E30 high-octane fuel vehicles (HOFVs) can also result in an increase in credit generation but the savings do not occur as quickly as the other fuel options examined here."*

…

- E85 use in PHEVs could increase cumulative GHG reductions under the LCFS by more than **25 million MT by 2030**. However, most of the GHG reductions attributable to E85 use in PHEVs come later in the study period because of the time needed to significantly penetrate the fleet with E85 PHEVs. In fact, E15 provides more cumulative GHG reductions than E85 in PHEVs until the 2028-2029 timeframe.
- High-octane E30 in HOFVs modestly boosts GHG savings over the baseline case, hitting nearly7 million MT CO2e by 2030. Most of the reductions from this fuel/technology pathway come later in the study period. Like E85 PEHVs, this is due to the time needed for HOFVs to significantly penetrate the fleet. (RFA1_80-1c)

Comment: *NextGen Supports the Inclusion of Charging Credits for New Modes of Transportation*

At pre-rulemaking workshops some stakeholders inquired as to whether charging activity that supported new modes of electrified travel, such as e-bicycles or electric aircraft, including drones, would be eligible for LCFS credits. Staff requested input from the community on this subject. At these workshops, some stakeholders expressed concern that these modes would result in a net increase in energy used by the transportation sector since they may increase the amount of flying, in the case of electric aircraft, or displace active or public transportation in the case of e-bikes. We feel that it is unlikely that such vehicles will account for a significant amount of energy consumption relative to the transportation sector as a whole, so including these new modes under the LCFS can help provide support for innovative modes of travel.

We suggest, however, that CARB limit the maximum credit generation for fuels delivered to these new modes to a relatively small fraction of the total credit generation until there is sufficient data to assess whether they, or any novel mode of transportation, would result in a significant net increase in transportation energy consumption. The LCFS is built on the fundamental assumption that alternative fuels displace conventional, high-emitting ones. If this displacement turns out to be untrue for some modes, CARB may need to re-assess their treatment under the LCFS. (NEXTGEN1_124-49)

Comment: The State and/or CARB should implement measures allocating funding to develop infrastructure, such as waste processing facilities and biomethane pipelines, that is needed to produce low-CI fuels to comply with the LCFS regulations as well as to meet the organic waste disposal reduction targets of SB 1383. This funding for waste processing facilities should not be limited to AD and composting facilities only and should also include non-combustion thermal conversion technologies (CTs) that can produce low-CI fuels and reduce emissions of methane and other GHGs. The availability of such infrastructure is crucial to achieve the 2020 and 2025 organic waste disposal reduction targets of 50 percent and 75 percent, respectively. The 88 cities in Los Angeles County and the County unincorporated communities currently have a maximum organic waste composting and AD processing capacity of approximately 0.5 million tons per year and approximately 1.3 million tons per year of chipping and grinding capacity. Additionally, it is estimated that jurisdictions in Los Angeles County also dispose over 3.5 million tons per year of organic waste. Additional composting and especially AD infrastructure, at an estimated cost of over one billion dollars, is needed to address this capacity shortfall. The Task Force believes that some funding assistance from Cap and Trade should be made to jurisdictions for the construction and operation of the needed facilities. (TASKFORCE1_89-3)

Comment: Iogen and AJW have long supported ARB's work to develop and integrate a Cost Containment Mechanism (CCM) into the LCFS program. The CCM provides more program stability and certainty in the event of credit market shortages. In 2011, Iogen and AJW supported ARB's work to outline a cost containment mechanism for the LCFS program by leading a subcommittee to develop an initial concept. During the 2015 program re-adoption, many of our suggestions were formally incorporated into the program.

However, today the CCM remains largely untested as credit prices have remained well below $200/ton. Because use of the CCM been fairly limited, it is somewhat difficult to project how it will operate in the event that LCFS credit demand drives prices significantly higher. Having said that, we are concerned that the requirement for repayment after five years of credit "debt" allowed under the CCM could create a programmatic weakness and undermine the purpose and functionality of the CCM. It is not unreasonable to anticipate that regulated parties facing uncertainty regarding how to meet long-term LCFS obligations might decide to either pay a higher LCFC credit price than the CCM price cap to ensure they have needed credits – or worse, choose to limit fuel supplies directed toward California.

External circumstances, like the speculated changes in the federal RFS could lead to significant price hikes of LCFS credit prices well ahead of expectations, in comparison with expected prices with both programs functioning in concert - even with the smoothed LCFS curve.

We believe that, in the event of prolonged market shortages, there will be increasing uncertainty related to possible outcomes of a CCM debt accumulation toward the 5-year window. This could easily translate into LCFS credit prices above $200, thus negating the goal of the price ceiling. In replacement of this 5-year repayment window, we

believe ARB could consider removing the 5-year limit completely, or providing a selective option to transfer or extend the term with Cap & Trade credits. If the 5-year repayment window is lifted, obligated parties will still carry the LCFS credit debt with interest and inflation, but they are able to repay when the market allows. We believe industry will not carry this debt longer than needed, and that the investment opportunities (and solutions offered by the market) will be enhanced by avoiding the uncertainty. (AJWIOGEN1_17-4)

Comment: Number 2: Cost-containment mechanism. We know that having a robust price ceiling is important to this Board. Howev -- or today's LCFS credit prices are strong, and that's a good thing for the program. However, there are additional measures that ARB should take to strengthen the cost-containment mechanism before the ceiling gets tested. (AJWIOGEN2_T2-3)

Comment: Because the proposed obligation reduction schedule is non-sustainable a strong mechanism for cost containment of credit prices is needed. Unfortunately, the current cost containment provisions create a substantial compliance liability, punitive to regulated parties; and may not actually contain costs. Andeavors concerns and recommendations to strengthen the program are as follows.

Concerns:

- Deficits are rolled over for up to five years with an interest penalty of five percent annually, after the initial five years CARB has not detailed a mechanism for resolution of that liability.
- Any entity participating in the LCFS program with a deficit is named along with their deficit volume, this exposes the named company to unnecessary financial risk given the competitive nature of the program.
- No buyer liability for purchasers of credits. Buyers may be forced to buy credits from parties they deemed credit unworthy in the normal market with no protection should those credits later be invalidated.

Recommendations:

- Revise the credit clearance market provisions to enable CARB to adjust or freeze targets in the face of growing, systemic deficits due to inadequate supply of credit-generating fuels. We recommend this occur after deficits remain unresolved after two consecutive credit clearance markets. Obligated parties would be required to clear any deficits incurred but, would be provided time with a sustainable credit supply to resolve the deficits. This would also allow time for the needed production or infrastructure advancements in the credit-generating fuels to catch-up to the demand.
- Allow for obligated parties to fund credit-generating projects as approved by CARB as an alternative to resolving the deficit through credit purchases. This approach was one of the original five cost containment concepts reviewed by CARB. Andeavor believes that adding this option, if designed properly, could

incent the types of projects that would provide long-term, sustainable credit generation that would bring stability to the program. There are many ways this program could be designed and Andeavor will provide CARB with additional detail on this concept in the near future.

- CARB to provide near-term program reviews. Such reviews would probably best occur every two years and would really only forecast credit supply in the one to three-year range. This would not be a re-visitation of the longer-term program goals every two years. This would be a very focused review to make sure that any near-term credit supply problems are discovered early where CARB could take proactive steps to address the problem and protect market participants and consumers from credit price volatility.
- Name the entity with a defecit but do not disclose the deficit volume. This will allow obligated parties to purchase credits for compliance in a manner that does not expose them to premium credit prices.
- Require the seller of credits in the Credit Clearance Market to retain the environmental and financial liability if deemed invalid. (ANDEAVOR1_67-4)

Comment: Considering these near-term challenges in reviewing the proposed CI targets for 2019 through 2030, we believe CARB should develop an improved cost-containment mechanism for the program.

The cost-containment mechanism should provide market participants a compliance pathway that is predictable, cost effective, and non-punitive.

In the Andeavor comments, I've detailed some specific concerns and recommendations. We believe the recommendations will provide a framework to meet the cost-containment challenge, with a goal of making the program more sustainable in the long run. (ANDEAVOR2_T10-5)

Comment: If future relaxations are required, these can be implemented in a few different ways. One possible approach would be to modify the credit clearance mechanism to drop the five-year constraint on carrying forward deferred obligations. This would broaden the quantitative relaxation available at the $200 price, making the mechanism more closely resemble a true price cap, but this change would raise two concerns. First, by letting participants accumulate open-ended quantities of deferred obligations, it would increase risk of compliance failure, by bankruptcy or other means. A compromise approach to limit this risk would be for ARB to grant such relaxations only case-by-case, subject to participant-specific assessment of default risk. Second, relying on the credit clearance mechanism as the vehicle for future relaxation would make most sense if ARB remained confident that the $200 credit price is the appropriate maximum: high enough to motivate major investment in innovations, but not so high as to risk serious disruption of fuel markets. If this is not the case, or if ARB does not want to rely on the clearance mechanism for this purpose, future loosening can also be achieved either by small explicit relaxation of forward CI targets, or implicitly by incremental expansions of the policy's scope to bring in additional low-CI fuels and uses, as was done for electric forklifts and rail system and is proposed for alternative jet

fuel. Limited expansions in credit eligibility for carbon capture and removal would be one way to achieve such small relaxation, subject to the caution above that such carbon removal crediting must be kept under careful quantitative control. Whatever method is considered, ARB must carefully resist too-easy or too-early relaxation, because sustained high credit prices will be necessary to generate the needed development and investment in low-CI alternatives. (UCLA1_B8-9)

Comment: The LCFS credit market is subject to a cap in credit values, limiting the maximum value of credits for fuel producers, but the program does not have a floor to ensure a minimum value for credits. A minimum value for LCFS credits would provide stability and confidence in the credit market, allowing investors to more accurately project revenue and mitigate the risk of financing new projects. (EIN1_B11-3)

Comment: Aside from this rulemaking, we want to flag, and our paper identifies, the value of considering establishing a market floor. The LCFS credit market is subject to a cap in credit values and eliminating the maximum value of credits for fuel producers, but the program doesn't have a floor to ensure minimum value for credits. A minimum value for LCFS credits would provide stability and confidence in the credit market, allowing investors to more accurately project revenue and mitigate the risks of financing new projects. (EIN2_T30-5)

Comment: And then last I know, this Board and the staff is very sensitive about cost. The current cost estimates of this program are pretty high as we look forward. And I do appreciate your attention on cost containment provisions, not only for consumers, businesses, but for us also, refinery workers.

And I just note one reference in the report that CARB put out that I think we should look at, if I may. This is the Standardized Regulatory Impact Assessment that was submitted in November of 2017. And I'll just note two elements that cumulatively through 2019 and 2030, the estimated total cost of the credits goes to go 8.8 billion. So I think cost containment is obviously why it's key on your list, certainly on the businesses. (WSPA4_T48-8)

Comment: The CHBC appreciates the great work of the Air Board's (ARB's) staff to continue to improve the Low Carbon Fuels Program (LCFS). The California Hydrogen Business Council (CHBC) would like to suggest a change to the LCFS Program to increase the adoption of renewable and zero carbon fuels like hydrogen to meet California's climate and emission reduction goals.

…

The CHBC recommends that ARB recognize a fuel cell battery hybrid electric bus (FCEB) as a battery electric bus (BEB) with the same EER value relative to diesel. FCEB propulsion is provided by an electric motor with energy coming from a battery, exactly like a BEB with the same efficiency. Therefore the EER should be calculated based on the bus energy consumption in kWh/mile like any other electric bus (using Altoona test data) and not based on hydrogen consumption.

The efficiency of the fuel cell module to convert hydrogen into electricity should be part of the electricity generation, transportation and charging efficiency.

The fuel cell module on board the bus is a battery charger; it should therefore be considered as an alternative way to charge batteries like on route opportunity charger or plug-in at a depot. Consequently, it should not be considered as part of the vehicle efficiency calculation but should be part of the charging system of the vehicle. (CHBC1_139-1)

Comment: In the 2009 LCFS, the EER of 1.0 for CNG vehicles relative to gasoline vehicles used in light-duty and medium duty applications and an EER of 3.0 for battery electric and plug-in hybrid electric light vehicles operating on electric power were developed by ARB. The LCFS accounted for the potential increases in gasoline engine efficiency by increasing the average fuel economy of light duty vehicles from 29 mpg by 30 percent to account for the impact of fuel economy standards. However, the LCFS does not account for the temperature effects which could potentially reduce the EER by 10 to 15% as noted in the previous section. The EPA tests are performed at 70° F without accessories, so that a more comprehensive EER estimate that includes winter and summer effects requires further study.

Currently there are no EV light trucks in the market except the Tesla Model X, but we anticipate SUV and passenger van models are likely to have EER values close to those for cars. However, battery electric cargo vans and pickups will have significant reduction in payload capability compared to gasoline models of similar size and an adjustment methodology to account for the payload capability is required to develop EER values for such vehicles (several small electric cargo vans are expected to be introduced in 2019/2020). (GROWTHENERGY1_B4-76)

Comment: The data shows remarkably consistent values with an average EER of 2.06, which is lower than the 2.3 value estimated by ARB. It is not clear how the fuel economy of the fuel cell deteriorates in hot and cold weather and this may change the estimated EER value (at 70 F without accessory loads) of 2.06 further. A lower value of EER consistent with the data is recommended for use.

Finally, the ISOR estimates a CNG vehicle EER of 1.0 which does not account for the increased weight of the CNG fuel tanks and reduced engine power. The now discontinued Civic CNG model was rated 41.15 mpg for the unadjusted EPA test value in MY2015, while the gasoline Civic model with the same 1.8L engine was rated at 44.78 mpg. This shows an EER of 0.92 which may be better than the EER of light duty CNG aftermarket conversions, which are the only light duty CNG vehicles now available. We would suggest an EER value of 0.9 as appropriate for aftermarket conversions. (GROWTHENERGY1_B4-78)

Comment:

- The EER value of 3.0 for electric light duty vehicles relative to gasoline vehicles may be appropriate for mild weather but is likely to be lower at more extreme ambient temperature
- The EER for Fuel cell light duty vehicles appears to be overstated based on the actual measured fuel economy data for the three fuel cell vehicles available commercially in 2018 (GROWTHENERGY1_B4-85)

Comment:

Vehicle Type	EER recommended by ARB	Suggested Correction
Battery Electric Cars (LDV)	3.0	Could be reduced by 10 to 15% in summer and winter
Battery Electric Light Duty Trucks (LDT)	3.0	As above, plus payload reduction in cargo trucks
Hydrogen Fuel Cell LDV	2.3	About 2.0, weather effects unknown
CNG LDV/LDT	1.0	0.9 for aftermarket conversions

(GROWTHENERGY1_B4-92)

Comment: We would ask CARB to consider treating locomotives and ocean-going vessels similar to jet fuel (i.e. exempt petroleum fuels and allow for opt-in status for low CI fuels). The case for including marine vessels is compelling as Europe is currently moving to incentivize bio in marine applications. (REG1_88-7)

Comment: As a transitional option, we propose that ARB allow the purchase or transfer of LCFS credits that were generated from renewable biogas to CNG or LNG to meet SB1505 requirements. These credits would not be transferred to obligated parties but instead, hydrogen producers could transfer these credits to ARB's buffer account. Such an approach would free up a source of renewable feedstock without obligating hydrogen producers to purchase an asset with an unusable RIN.

In order to implement this approach for one million Btu of hydrogen, ARB could allow hydrogen producers to obtain and transfer to ARB the LCFS credits that were associated with RNG. Table 1 shows the LCFS credits associated with 1 million Btu of RNG that could be used as feedstock for hydrogen production. We recommend that hydrogen producers be allowed to work with RNG credit generators to determine the amount of LCFS credits per mmBtu of RNG or that ARB assigns a default value. The LCFS credits generated depend on the baseline CI, CI for RNG, and the EER for the pathway. In the example below 70.21 credits would be generated for 1000 mmBtu of

RNG. ARB could use this credit generation rate to allow for the calculation of renewable biogas feedstock to meet SB1505 compliance.

Table 1. Calculation of LCFS Credits Generated per mmBtu of Renewable Biogas.

	Baseline	Biogas	Delta
Biogas Needed (scf)		1,075,269	
(Therms)		11,075	
(mmBtu, LHV)		1,000	
EER		0.90	
Fuel Energy (GJ, LHV)	857	1,055	
Fuel CI (g/MJ)	93.0	10.00	
WTW GHG Emissions (tonne)	79.73	9.53	**70.21**
			Credits
	0.0702	Credits/mmBtu, LHV	

We propose that ARB allow hydrogen producers to apply these credits in proportion to the mmBtu of natural gas feedstock used for hydrogen production. The hydrogen producer could transfer to credits to ARB's account for retirement. In order to implement this approach, ARB would need to determine the fate of the credits. For example the credits could be retired and not used to meet the compliance obligation or ARB could apply them to a buffer account to address issues associated with credit shortfalls.

This implementation of this option would be straightforward from the fuel producer's perspective. Fuel producers could either generate credits for RNG to hydrogen pathways or they could obtain RNG credits and transfer the credits to ARB. Fuel producers could track the quantity of renewable hydrogen and their total hydrogen sales for transportation to verify compliance with the 33.3% renewable requirement under SB 1505.

We recommend that ARB allow the option to apply RNG based LCFS credits for a period of 10 years to allow for the development of additional biogas resources as well as the alignment of the RFS program with renewable hydrogen. (LINDE1_20-1)

> **Agency Response:** Staff appreciates the commenters' insights but notes that these recommendations are not within the scope of this rulemaking because the modifications discussed in the comment were not incorporated in the proposed revisions or included in the notice of changes.
>
> In response to CT1_4-1, it is unclear what list of biodiesel companies the commenter is referring to, but staff would like to note that RIN (assuming this is a reference to the U.S. EPA Renewable Fuels Standard denomination of a credit) fraud or abuse is one of the considerations that lead staff to propose a system for third-party verification with substantial CARB oversight to detect fraud, errors and misreporting in the LCFS.

In response to CT1_4-2, staff would like to clarify for the commenter that a producer of algae-derived fuel would certainly be recognized under the LCFS.

In response to TASKFORCE1_89-3, staff notes that several amendments are proposed to support the organic waste diversion and methane reduction goals of SB 1383 and the Short Lived Climate Pollutant Strategy, including: the classification of biomethane pathways as Tier 1 and the development of Simplified CI Calculators for these fuels; the crediting period proposed in section 95488.9(f); and the addition of biomethane as a fuel that is eligible for crediting under the innovative crude provisions, as well as the use of biomethane in hydrogen production, for use as a transportation fuel, or in the production of a transportation fuel e.g., at refineries.

In response to comment AJWIOGEN1_17-4, AJWIOGEN2_T2-3, ANDEAVOR1_67-4, ANDEAVOR2_T10-5, UCLA1_B8-9, EIN1_B11-3, EIN2_T30-5, and WSPA4_T48-8, staff realizes the importance of an effective cost containment mechanism and is committed to working with stakeholders to update the cost containment provisions in the LCFS program.

In response to CHBC1_139-1, staff would like to clarify the Energy Economy Ratio means the dimensionless value that represents the efficiency of a fuel as used in a powertrain as compared to a reference fuel used in the same powertrain. In fuel cell busses, although hydrogen is being converted to electricity for powering the electric motors, the hydrogen is the fuel that is displacing the reference fuel used in similar application. Whereas, for battery electric busses the fuel that is displacing the reference fuel is electricity. Therefore, the EER for heavy-duty fuel cell vehicles determined based on hydrogen consumption. Moreover, if the hydrogen system efficiency is not accounted in EER, it would need to be incorporated into the life cycle assessment of hydrogen for determining the CI. This would create unnecessary complexity as the fuel provider would have to keep track of vehicle types in which hydrogen is being used and keep a track of their fuel system efficiencies for CI determination. The proposed EER for heavy-duty fuel cell vehicles, including FCEBs, is an average value to be available for reporting hydrogen use in a variety of heavy-duty fuel cell vehicles. This provides simplicity and ease for reporting hydrogen in the LCFS.

In response to GROWTHENERGY1_B4-76, GROWTHENERGY1_B4-78, GROWTHENERGY1_B4-85, and GROWTHENERGY1_B4-92, the data available to staff did not support any updates to the EER values for light-duty category, CNG, and fuel cell vehicles. Staff is committed to re-evaluating these EER values as and when relevant data is available.

In response to REG1_88-7, staff is committed to working with stakeholders for expanding the LCFS program to further incentivize the use of low-carbon transportation fuels.

In response to LINDE1_20-1, staff would like to clarify that LCFS credits generated for using renewable natural gas as a transportation fuel in CNG or LNG vehicles cannot be used for meeting the renewable feedstock content requirements for hydrogen production under SB 1505. Such an approach would result in two fuels, the renewable natural gas used in CNG or LNG vehicles and the hydrogen used in fuel cell vehicles, being designated as renewable based on the same quantity of renewable natural gas. This would result in double-counting of the renewable attribute of the renewable natural gas.

W-5. Multiple Comments: *Support for Other Commenters*

Comment: The LCFS is supported by a broad and diverse coalition of California business, scientific, health and community stakeholders who recognize the unique value it provides.[4]

[4] We note that NextGen joined a group of stakeholders from the California Delivers Coalition on a letter of support for the re-adoption of the LCFS at a higher CI target than staff's original proposal. The provisions of that letter and this one are entirely compatible.

(NEXTGEN1_124-2)

Comment: Phillips 66 is a member of the Western States Petroleum Association (WSPA) and support the comments provided by that Association. (P661_55-1)

Comment: We are a member of the Western States Petroleum Association (WSPA) and we support the comments submitted by WSPA in response to this proposed rulemaking. (CHEVRON1_112-1)

Comment: Additionally, Andeavor is a member of the Western States Petroleum Association (WSPA), we support and incorporate by reference the comments provided on behalf of WSPA. (ANDEAVOR1_67-1)

Comment: Should the Agency proceed with modifying the LCFS as proposed, Valero supports and incorporates by reference the joint comments submitted by the Western States Petroleum Association on April 18, 2018 and April 23, 2018, to the extent they do not conflict with our position stated herein. (VALERO1_69b-2)

Comment: <u>SCE also supports the California Electric Transportation Coalition's (CalETC's) April 23 comments regarding the proposed changes to the LCFS</u>. (SCE1_108-4)

Comment: You'll see the Southern California Public Power Authority, Northern California Power Authority, PG&E, Edison, SDG&E, SMUD, LADWP, and CalETC are all here. We all support the CalETC letter. Please read it. (UTILITIES1_T47-1)

Comment: Coltura endorses the comments submitted by the Smart EV Charging Group on April 23, 2018 regarding the California Air Resources Board's Pre-Rulemaking on Low Carbon Fuel Standard.

Our organization aims to reduce the environmental impact of transportation by phasing out gasoline and diesel vehicles and moving to clean alternatives. We believe the proposal submitted by the Smart EV Charging Group supports an accelerated transition to a zero emissions transportation future, and therefore we support it.

Electric vehicles and charging infrastructure are being deployed with increasing success. However, to maximize the positive environmental benefits of this trend, a corresponding increase in charging sources with low emissions intensity is needed. We believe that lowering the emissions associated with charging through cleaner generation sources, on-site generation of renewables, and/or charging during times of the day and year when clean generation is abundant are all effective means to achieve this. (COLTURA1_136-1)

Comment: I am writing on behalf of Menlo Spark to support and endorse the comments submitted by the Smart EV Charging Group on April 23, 2018 regarding the California Air Resources Board's Pre-Rulemaking on Low Carbon Fuel Standard. (MENLO1_137-1)

Comment: The proposal submitted by the Smart EV Charging Group would support the accelerated transition to the low-GHG transportation future we envision by increasing the charging sources with low or no emissions intensity.

Electric vehicles and charging infrastructure are being deployed with increasing success across San Mateo County and our State. However, to maximize the positive environmental benefits of this trend, the State needs a corresponding increase in charging sources with low emissions intensity. Lowering the emissions associated with charging through cleaner generation sources, on-site generation of renewables, and/or charging during times of the day and year when clean generation is abundant are all effective means to achieve this. (MENLO1_137-2)

Comment: MBCP endorses the comments submitted by Sonoma Clean Power Authority (SCP) regarding the 2018 proposed amendments to the LCFS Regulation.

Reducing the environmental impact of transportation systems is a central goal of our organization. We believe the comments submitted by SCP would support the accelerated transition to the low-GHG transportation future we envision for our service territory, by ensuring that the LCFS Regulation accurately reflects the Carbon Intensity of different retail electricity mixes and allows all Load Serving Entities the chance to administer the credits generated by their EV customers.

Electric vehicles and charging infrastructure are being deployed with increasing success across our Counties and State. However, to maximize the positive environmental benefits of this trend, the State needs a corresponding increase in charging sources with low emissions intensity. We believe that lowering the emissions associated with charging through cleaner generation sources (like SCP, MBCP, and other CCA service offerings), on-site generation of renewables, and/or charging during times of the day

and year when clean generation is abundant are all effective means to achieve this. (MBCP1_33-1)

Comment: 4. San Francisco supports the concepts proposed by the Clean Charging Coalition to increase and recognize the role of Community Choice Aggregators and others in promoting the use of Electric Vehicles (EVs).
…

San Francisco supports the concepts proposed by the Clean Charging Coalition to increase and recognize the role of Community Choice Aggregators and others in promoting the use of Electric Vehicles (EVs).

In addition to operating a publicly-owned utility, San Francisco has also recently begun (starting in May 2017) operations as a Community Choice Aggregator (CCA) through its CleanPowerSF program. CleanPowerSF currently offers San Francisco's residents and businesses the opportunity to procure electric power that has less GHG-emissions than that provided by PG&E, their current energy provider.

The Clean Charging Coalition, a group composed of EV charging entities and many California CCA's have proposed changes to the LCFS regulations that would increase the opportunity for CCAs to receive LCFS credits for the clean energy and infrastructure development they provide to their customers purchasing EVs.

San Francisco supports these efforts. (CCSF1_87-4)

Comment: And my comments are in support of the comments -- or the written comments from the Bioenergy Association of California. (GLB1_T22-1)

Comment: We support BAC comments today and fellow RNG operators. (CCC1_T52-1)

Comment: As members of both the California Advanced Biofuels Association and the National Biodiesel Board (NBB), we wish to align ourselves with the comments they have submitted. (REG1_88-2)

Comment: I first want to align my comments with those of our member company, Renewable Energy Group. (NBBCABA2_T23-1)

Comment: We would like to align our comments with the Renewable Natural Gas Coalition, Bioenergy Association of California and the Western Propane Gas Association. (CNGVC1_118-1a)

Comment: So if -- as Julia said, if we could -- if you could look at the other three suggestions. And we really appreciate the staff looking at that and taking those recommendations, the one that you already implemented. But look at the other three. And if you could review those, and as you have barbecues coming up this weekend and over the summer, just ask your -- and tell your friends how we all can contribute to

making a difference. And look at those other three suggestions and make this documentation -- the standard even better. (GLB1_T22-3)

Comment: We've also had quite a few folks that have commented that are in our kind of technology and fuel space that made some great comments, and we would add our agreement with what they have said. (CNGVC2_T32-1)

Comment: These comments are in addition to our occurrence with the comments submitted by Noyes Law Corporation on behalf of the AJF Producers. (LANZATECH1_77-2a)

Comment: I'll keep my comments relatively brief today, as we largely align with San Francisco International Airports. (CAC2_T21-1)

> **Agency Response:** Staff acknowledges these stakeholder comments in support of comments provided by other organizations. All comments submitted by the referenced organizations have been responded to elsewhere in the FSOR.
>
> In response to comment GLB1_T22-3, please see Responses T-3.3, F-3.1 and J-10.3 in this chapter.

W-6. *General Criticisms of the Low Carbon Fuel Standard*

W-6.1. *Corn-Based Biofuels*

Comment: To date corn-based biofuels (ethanol and DCO Biodiesel) are directly responsible for more than 50% of the program's carbon reductions as measured by carbon credit generation. We believe there are still plenty of benefits that can be provided by our industry so long as a level market playing field is maintained. <u>RPMG respectfully requests that the Board direct staff to continue working on the following identified issues through a 15-day amendment process.</u> (RPMG1_64-2)

> **Agency Response:** Staff agrees that corn ethanol and biodiesel derived from distiller's corn oil have generated a substantial portion of total credits in the LCFS to date, though staff would like to clarify that the total contribution is 43 percent. The LCFS has thus provided significant economic benefits to the corn biofuel industry, and is expected to continue to do so under staff's proposal. As the benchmarks continue to decline under the proposal, credit generation can be maximized by continued improvements to the efficiency of biofuel supply chains, and by utilizing low-CI process energy inputs such as biomethane and solar power. Additionally, staff's proposal provides new credit generation opportunities to this industry such as the ability to generate credits for carbon capture and sequestration.

W-6.2. Multiple Comments: *Program Feasibility*

Comment: Diamond Green Diesel has significant concerns that the proposed modifications to the LCFS program run counter to the purpose of the program and the

underlying statute. The Agency is ostensibly proposing to amend the LCFS program regulation to reflect actual current market penetration of alternative fuels and provide pathways to grow the use of these fuels over the life of the program in an effort to achieve the 2030 reduction target. Many of the proposed amendments appear to undermine the quality control systems and overall compliance mechanisms in an effort to promote the growth of credits produced by alternative fuels in order to provide liquidity and achieve program feasibility. (DGD1_69a-1)

Comment: Valero has significant concerns that the proposed modifications to the LCFS program run counter to the purpose of the program and the underlying statute. The Agency is ostensibly proposing to amend the LCFS program regulation to reflect actual current market penetration of alternative fuels and provide pathways to grow the use of these fuels over the life of the program in an effort to achieve the 2030 reduction target. Many of the proposed amendments appear to undermine the quality control systems and overall compliance mechanisms in an effort to promote the growth of credits produced by alternative fuels in order to provide liquidity and achieve program feasibility. The proposed structure of the amendments will ultimately discourage refiners from lowering the carbon intensity of the fuels they produce. (VALERO1_69b-1)

> **Agency Response:** It is unclear what specific modifications the commenters are concerned may "run counter to the purpose of the program," or "undermine the quality control systems and overall compliance mechanisms." Staff agrees, as stated in the ISOR (Chapter II, p. 1), that some of the primary goals of the amendments are to increase the 2030 target and expand credit generating opportunities in order to encourage additional greenhouse gas reductions in specific areas where decarbonization will be important to meet California's long-term climate goals. Promoting growth of alternative fuels as a means of reducing greenhouse gas emissions, decreasing dependence on petroleum, and diversifying the fuel pool, are primary objectives—not solely of the amendments, but of the LCFS since its inception.

W-6.3.*Additionality*

Comment: *NextGen Suggests CARB Review How the LCFS Assesses Additionality Where Other Policies Change Emissions From a Transportation Fuel System*

Additionality, in life cycle analysis, means that effects must have been caused by a particular project, product, or process in order for their effects to be considered as a result of that project, product or process. In essence, a change in emissions must be predominantly because a given fuel is used if that fuel is to receive LCFS credits for reducing emissions. Under a comprehensive climate portfolio, like California's, there are likely to be multiple policies affecting emissions of projects, processes or products which are inputs to a transportation fuel. CARB should seek to balance the scientific imperative to base policy on an assessment of emissions under the strongest methodology against the need to create a stable and sufficient incentive for deployment of advanced fuel systems.

Staff have indicated that at present, they typically allow credit generation to claim benefits from reduced emissions of greenhouse gases for up to 10 years after such emissions would have been controlled by other policies. There is no scientific justification for why emissions should be credited as reductions for 10 years after they would have, in fact, been reduced. We urge CARB to re-evaluate such provisions and determine whether so long a period of crediting after the emissions have been controlled is, in fact, necessary to support critical investment in low-carbon fuels. We urge staff to err on the side of science when making decisions relating to additionality. (NEXTGEN1_124-52)

> **Agency Response:** It is unclear which provision(s) the commenter is referring to, and staff disagrees with the assertion that it is typical practice to allow credit generation for up to 10 years after emissions would have been controlled by other policies. In fact, it is general practice under the LCFS not to credit reductions that are required by law. However, exceptions do exist for specific circumstances. A 10-year crediting period is provided for dairy and swine manure methane projects that are voluntary under current law, in the event that mandatory methane reductions are enacted in the future. This is consistent with crediting under CARB's Cap-and-Trade Regulation, and is required by statute (SB 1383).

W-6.4. Multiple Comments: *General Concerns*

Comment: We are concerned that some of the regulatory text modifications proposed by CARB could create unnecessary administrative burdens and increased cost with little or no additional regulatory benefit. Further, we believe some of the planned amendments could have the unintended consequence of stifling the innovation and investment that could lead to additional carbon intensity (CI) reductions under the LCFS. As such, we encourage CARB to seriously consider the recommendations below prior to promulgating the proposed regulatory amendments. (RFA1_80-2)

Comment: We believe that our recommendations will strengthen the LCFS program and promote additional private investments in low carbon intensity (low-CI) projects, including dairy biomethane, allowing the LCFS program to successfully reduce the carbon intensity of California fuels by 20% by 2030.

…

These comments and proposed changes will promote investments in low-CI projects, especially dairy biomethane, furthering the aims of the overall LCFS policy and its stakeholders. (AMP1_86-1)

Comment: BAC supports many of the proposed changes, but objects to several of the changes that would impede the state's progress in reducing Short-Lived Climate Pollutants and meeting the biofuels goals in the 2030 Scoping Plan Update. (BAC1_99-2)

Agency Response: Staff acknowledges the commenters' general concerns, and responds to the specific recommendations elsewhere.

V. SUMMARY OF COMMENTS MADE DURING THE FIRST 15-DAY COMMENT PERIOD AND AGENCY RESPONSES

Chapter V of this FSOR contains all comments submitted during the first 15-day comment period with CARB's responses. The first 15-day comment period for additional proposed amendments commenced on June 20, 2018, and ended on July 6, 2018.

CARB received 72 comment letters on the proposed 15-day amendments during the 15-day comment period. Table V-1 below lists the commenters that submitted written comments on the proposed amendments during the first 15-day comment period, identifies the date and form of their comments, and shows the abbreviation assigned to each.

The individually submitted comment letters for the 45-day, first 15-day, and second 15-day comment periods are available here: https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm

Note that some comments were scanned or otherwise electronically transferred, so they may include minor typographical errors or formatting that is not consistent with the originally submitted comments. However, all content reflects the submitted comments. All originally submitted comments are available here: https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm.

Comments that address the draft Environmental Analysis are responded to in the "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuels Regulations."

A. List of Commenters

Listed below are the organizations and individuals that provided comments during the first 15-day comment period:

Table V-1. List of Commenters During the First 15-Day Comment Period

Comment Letter Code	Commenter
FF_OCCIDENTAL3_FF1	Al Collins, Occidental Petroleum Corporation First 15-Day Comment: June 21, 2018
FF_CAF2_FF2	Patrick J. McDuff, California Fueling First 15-Day Comment: June 26, 2018
FF_PROTERRA2_FF3	Kent Leacock, Proterra, Inc. First 15-Day Comment: June 29, 2018
FF_NBBCABA3_FF4	Jennifer Case, California Advanced Biofuels Alliance Shelby Neal, National Biodiesel Board First 15-Day Comment: July 2, 2018
FF_MEG1_FF5	Richard Mattocks, Martin Energy Group First 15-Day Comment: July 2, 2018
FF_POLB1_FF6	Heather A. Tomley, Port of Long Beach First 15-Day Comment: July 3, 2018

FF_TASKFORCE2_FF7	Margaret Clark, Los Angeles County Solid Waste Management Committee/Integrated Waste Management Task Force First 15-Day Comment: July 3, 2018
FF_BP2_FF8	Ralph J. Moran, BP America, Inc. First 15-Day Comment: July 3, 2018
FF_FHR2_FF9	Philip Guillemette, Flint Hills Resources First 15-Day Comment: July 3, 2018
FF_LADWP2_FF10	Mark J. Sedlacek, Los Angeles Department of Water and Power First 15-Day Comment: July 3, 2018
FF_VALERO2_FF11	Elizabeth A Hepp, Valero First 15-Day Comment: July 3, 2018
FF_DGD2_FF12	Elizabeth A Hepp, Diamond Alternative Energy LLC dba Diamond Green Diesel First 15-Day Comment: July 3, 2018
FF_UNITED2_FF13	Aaron Robinson, United Airlines First 15-Day Comment: July 3, 2018
FF_PMSA1_FF14	Thomas Jelenić, Pacific Merchant Shipping Association First 15-Day Comment: July 3, 2018
FF_A4A2_FF15	Nancy N. Young, Airlines for America First 15-Day Comment: July 5, 2018
FF_AP1_FF16	Brian B. Bonner, Air Products First 15-Day Comment: July 5, 2018
FF_H2IND2_FF17	David P. Edwards, PhD, Air Liquide Dr. Shane Stephens, FirstElement Fuel Stephen Ellis, American Honda Motor Co, Inc. Debbie Bakker, Hyundai Kia America Technical Center, Inc. Nitin Natesan, Linde LLC Matthew Forrest, Mercedes-Benz Research & Development North America, Inc. Mikael Sloth, NEL Hydrogen A/S Wayne Leighty, MBA, PhD, Shell New Energies Michael Lord, Toyota Motor North America Joe Gagliano, United Hydrogen Jeff Serfass, California Hydrogen Business Council Brian Goldstein, Energy Independence Now First 15-Day Comment: July 5, 2018
FF_AAMGA1_FF18	Steven Douglas, Alliance of Automobile Manufacturers Julia Rege, Association of Global Automakers, Inc. First 15-Day Comment: July 5, 2018
FF_WSPA5_FF19	Catherine Reheis-Boyd, Western States Petroleum Association First 15-Day Comment: July 5, 2018
FF_DTEBE2_FF20	Mark Cousino, DTE Biomass Energy Inc. First 15-Day Comment: July 5, 2018

FF_ECOENGINEERS2_FF21	John Sens, EcoEngineers First 15-Day Comment: July 5, 2018
FF_WE3_FF22	Kim Do, White Energy, Inc. First 15-Day Comment: July 5, 2018
FF_KORE1_FF23	Graham Noyes, Noyes Law Corporation on behalf of Kore Infrastructure First 15-Day Comment: July 5, 2018
FF_FULCRUM2_FF24	Ted Kniesche, Fulcrum BioEnergy, Inc. First 15-Day Comment: July 5, 2018
FF_DGD3_FF25	Elizabeth A. Hepp, Diamond Alternative Energy LLC dba Diamond Green Diesel First 15-Day Comment: July 5, 2018
FF_SCG3_FF26	Kevin Maggay, SoCalGas First 15-Day Comment: July 5, 2018
FF_VALERO3_FF27	Elizabeth A. Hepp, Valero First 15-Day Comment: July 5, 2018
FF_USC3_FF28	Jeremy Martin, Union of Concerned Scientists First 15-Day Comment: July 5, 2018
FF_AJFP4_FF29	Graham Noyes, Noyes Law Corporation on behalf of Alternative Jet Fuel Producers First 15-Day Comment: July 5, 2018
FF_RFA3_FF30	Geoff Cooper, Renewable Fuels Association First 15-Day Comment: July 5, 2018
FF_CASA2_FF31	Greg Kester, California Association of Sanitation Agencies First 15-Day Comment: July 5, 2018
FF_BART2_FF32	Thomas W. Solomon, Winston & Strawn on behalf of San Francisco Bay Area Rapid Transit District First 15-Day Comment: July 5, 2018
FF_CARBONENG1_FF34	Geoffrey Holmes, Carbon Engineering First 15-Day Comment: July 5, 2018
FF_AECA3_FF35	Michael Boccadoro, Agricultural Energy Consumers Association First 15-Day Comment: July 5, 2018
FF_IOGEN1_FF36	Amanda Black, Iogen Corporation First 15-Day Comment: July 5, 2018
FF_OCCIDENTAL4_FF37	Al Collins, Occidental Petroleum Corporation First 15-Day Comment: July 5, 2018
FF_UNICA3_FF38	Leticia Phillips, Brazilian Sugarcane Industry Association (UNICA) First 15-Day Comment: July 5, 2018
FF_CHARGEPOINT3_FF39	Anthony Harrison, ChargePoint, Inc. First 15-Day Comment: July 5, 2018
FF_MEW1_FF40	Daryl Maas, Maas Energy Works, Inc. First 15-Day Comment: July 5, 2018

FF_RPMG3_FF41	Jessica W. Hoffmann, RPMG Inc. First 15-Day Comment: July 5, 2018
FF_CRF2_FF42	Tim Morillo, Calgren Renewable Fuels First 15-Day Comment: July 5, 2018
FF_CIPA2_FF43	Rock Zierman, California Independent Petroleum Association First 15-Day Comment: July 5, 2018
FF_REG3_FF44	Scott R. Hedderich, Renewable Energy Group, Inc. First 15-Day Comment: July 5, 2018
FF_EMW1_FF45	David Schlosberg, Electric Motor Werks, Inc. First 15-Day Comment: July 5, 2018
FF_RNGC3_FF46	Nina Kapoor, Coalition for Renewable Natural Gas First 15-Day Comment: July 5, 2018
FF_CF1_FF47	John A. Thornton, CleanFuture First 15-Day Comment: July 5, 2018
FF_TWC1_FF48	Ilia Florentin, The Wonderful Company First 15-Day Comment: July 5, 2018
FF_NRDC3_FF49	Simon C. Mui, Natural Resources Defense Council First 15-Day Comment: July 5, 2018
FF_LYFT1_FF50	Sam Arons, Lyft, Inc. First 15-Day Comment: July 5, 2018
FF_CCSF3_FF51	James Hendry, City and County of San Francisco acting through the San Francisco Public Utilities Commission and the San Francisco Municipal Transportation Agency First 15-Day Comment: July 5, 2018
FF_CE4_FF52	Todd Campbell, Clean Energy Fuels Corporation First 15-Day Comment: July 5, 2018
FF_SREC2_FF53	Steven Eisenberg, SRECTrade First 15-Day Comment: July 5, 2018
FF_GLASSPOINT2_FF54	John O'Donnell, GlassPoint Solar, Inc. First 15-Day Comment: July 5, 2018
FF_CATFNRDC1_FF55	Briana Mordick, Natural Resources Defense Council George Peridas, Natural Resources Defense Council L. Bruce Hill, Clean Air Task Force James P. Duffy, Clean Air Task Force Deepika Nagabhushan, Clean Air Task Force First 15-Day Comment: July 5, 2018
FF_GROWTHENERGY2_FF56	Chris Bliley, Growth Energy First 15-Day Comment: July 5, 2018
FF_SHELL2_FF57	Sara O'Neill, Shell Oil Company First 15-Day Comment: July 5, 2018
FF_WPGA3_FF58	Joy Alafia, Western Propane Gas Association First 15-Day Comment: July 5, 2018
FF_CNGVC3_FF59	Thomas Lawson, California Natural Gas Vehicle Coalition First 15-Day Comment: July 5, 2018

FF_CALETC3_FF60	Eileen Wenger Tutt, California Electric Transportation Coalition First 15-Day Comment: July 5, 2018
FF_SEVCG3_FF61	Neal Reardon, Sonoma Clean Power Authority on behalf of the Smart EV Charging Coalition First 15-Day Comment: July 5, 2018
FF_EVGO1_FF62	Sara Rafalson, EVgo First 15-Day Comment: July 5, 2018
FF_SMUD2_FF63	William W. Westerfield, III and Bill Boyce, Sacramento Municipal Utility District First 15-Day Comment: July 5, 2018
FF_PGE2_FF64	Fariya Ali, Pacific Gas and Electric First 15-Day Comment: July 5, 2018
FF_NEXTGEN3_FF65	Colin Murphy, NextGen California First 15-Day Comment: July 5, 2018
FF_BMW1_FF66	Adam Langton, BMW of North America, LLC First 15-Day Comment: July 5, 2018
FF_CALBIO1_FF67	Neil Black, California Bioenergy LLC First 15-Day Comment: July 5, 2018
FF_LCA6_FF68	Stefan Unnasch and Love Goyal, Life Cycle Associates, LLC First 15-Day Comment: July 5, 2018
FF_TESLA2_FF69	Fei Chi, Tesla, Inc. First 15-Day Comment: July 5, 2018
FF_BLUESOURCE1_FF70	Will Overly, Bluesource LLC First 15-Day Comment: July 5, 2018
FF_FEF1_FF71	Dr. Shane Stephens, FirstElement Fuel Inc. First 15-Day Comment: July 5, 2018
FF_WSPA6_FF72	Catherine Reheis-Boyd, Western States Petroleum Association First 15-Day Comment: July 5, 2018

B. General Comments in Support of the Proposed Amendments

B-1. Multiple Comments: *General Support for the Proposed Amendments*

Comment: Proterra strongly supports the LCFS and efforts to encourage the use and production of cleaner low-carbon fuels in California. (PROTERRA2_FF3-1)

Comment: LADWP reaffirms its strong support of the LCFS program and its role in achieving the substantial greenhouse gas (GHG) emissions reductions goals of AB 32 and SB 32. (LADWP2_FF10-1)

Comment: We appreciate and support ARB staff's effort to continually update and improve upon the LCFS, and as described below, we support the changes in the latest update to the LCFS regulations, including many of those in the subject LCFS 15-Day

Notice. In addition, we look forward to continuing to work with ARB on additional 15-day amendments that can help further the PEV market through, for example, potential point-of-purchase PEV rebates based upon credits generated from residential electric vehicle (EV) charging.[3]

[3] In response to direction from the Board, our associations are coordinating with CalETC and a broad group of California utilities to outline a point-of-purchase PEV rebate and detail a long-lasting rebate that can help support and increase PEV sales as we strive to meet the Governor's goals for PEV deployment. Details regarding this rebate will be shared in the near future, including addition of 15-day changes to the LCFS.

(AAMGA1_FF18-1)

Comment: On behalf of our more than 75,000 supporters in California, the Union of Concerned Scientists strongly supports the 2018 Low Carbon Fuel Standard (LCFS) amendments proposed in the Initial Statement of Reasons. We were very pleased that the Board resolved in April to advance the process of finalizing these amendments. (UCS3_FF28-1)

Comment: Again, BART fully supports CARB's goal of reducing California's GHG emissions, and to this end appreciates CARB's efforts to continue to improve the LCFS Regulation. (BART2_FF32-7)

Comment: The comments provided here pertain to the 15-day amendment package. RPMG would like to acknowledge and state our support and appreciation for the changes already undertaken in the following sections:

- Extended Transfer Period – Section 95483(a)(3)
- Updated Substantiality Provisions – Section 95488.9(a)
- Addition of a quarterly verification option – Section 95500(b)(2)(C)
- Removal of restrictive Conflict of Interest – Section 95503(b)(2)
- Updated default corn transport distance – Simplified Calculator
- Inclusion of biogas and biomass energy consumption – Tier 1 Simplified CI Calculator
- Additions of fields 1.6 Application Description and 1.8 Provisional Pathway identifier to the Tier 1 Simplified CI calculator (RPMG3_FF41-1)

Comment: We appreciate the California Air Resources Board (CARB) and staff's goal of improving the effectiveness of the LCFS program and support several proposed modifications that will help to do so. (RNGC3_FF46-1)

Comment: CleanFuture strongly supports the LCFS and CARB's efforts to encourage the use and production of cleaner low-carbon fuels. (CF1_FF47-1)

Comment: The Wonderful Company supports the LCFS program and ARB's efforts to improve air quality and reduce climate impacts. We believe that the changes recommended herein will result in a stronger LCFS program and help foster the

development of projects needed to support the state's organic waste diversion and SLCP goals. (TWC1_FF48-8)

Comment: Clean Energy remains a committed supporter of California's LCFS program and appreciates ARB staff's diligent work and collaboration with industry stakeholders throughout the regulatory amendment process. We commend staff for addressing a number of concerns during this latest round of amendments as expressed in our previous comment letters. (CE4_FF52-1)

Comment: GlassPoint strongly supports CARB's work to improve the program. (GLASSPOINT2_FF54-9)

Comment: The CNGVC applauds the CARB in its goal to transition from fossil fuels to cleaner alternatives, and the staff`s tireless work to improve the LCFS program. It is important for the modifications to the LCFS incentivize adoption of all renewable clean energy equally and does not create unnecessary barriers that hinder the market for LCFS credit. In order for the Board to reach its goals to reduce carbon intensity (CI) of the transportation fuel pool by 2020, it must be aggressive in promoting energy diversification. This will help the state depart from fossil fuels and allow for a cleaner and more competitive energy market. The more options for cleaner fuel and technology will provide the transportation sector with greater choices and promote the adoption of vehicles that use alternative clean energy.

A major focus of the Coalition is to advocate for the use of renewable natural gas in transportation that helps California decarbonize its vehicle fleets, in doing so, provide better air for all residents of the State. As you know, the transportation sector is responsible for 40% of GHG emissions, renewable natural gas has already shown itself to be essential in reducing emissions. We hope that with the Board`s leadership that renewable natural gas will be instrumental to meeting the ambitious goals that California has established. (CNGVC3_FF59-1)

Comment: CalETC supports the LCFS, a program that has been successful thus far in reducing the carbon intensity of California's transportation fuel. Given the near-total dependence on oil in the transportation fuels sector, the LCFS is essential to both diversify the transportation fuels sector and reduce emissions from carbon-based fuel. (CALETC3_FF60-1)

Comment: 7. CalETC supports the additional 15-day modifications (e.g., provisions on smart charging, non-residential charging, low-carbon intensity charging, credit transfers, meter calibration, return of benefits).[20]

[20] For example, see section 95483(c)(1)(B), section 95481(c)(1)(B), section 95488.1(b), section 95488.5 (e) and (f), section 95483(a)(3), section 95487, section 95488.8(i), section 95491.1(c)(1)(G), section 95488.5(f)

(CALETC3_FF60-19)

Comment: SMUD is generally supportive of Staff's suggested modifications, which we will explain in detail below. (SMUD2_FF63-1)

Comment: PG&E continues to strongly support California's greenhouse gas (GHG) emission reduction goals as established in Assembly Bill 32 and Senate Bill 32. Maintaining a well-designed LCFS program that advances low-carbon fuels will play a key role in achieving the state's 2030 greenhouse gas emissions reduction targets. We believe that the increased use of electricity, conventional and renewable natural gas, and hydrogen as fuels is critical for the success of the LCFS program. (PGE2_FF64-1)

Comment: PG&E continues to support the Low Carbon Fuel Standard as a program that will help the state meet its aggressive environmental goals while maintaining a healthy economy. (PGE2_FF64-10)

Comment: The LCFS is a key element of California's climate and clean energy leadership. The current rulemaking to amend and extend the LCFS is a critical opportunity to put California on a path towards long-term sustainability. The LCFS plays a crucial role as the state works to attain the SB 32 target and set a course for even deeper cuts after 2030. California cannot achieve its climate or air quality goals without significant progress in the transportation sector. It is therefore crucial that the LCFS achieve the fullest extent of its potential to drive down emissions and support advanced clean energy technologies. (NEXTGEN3_FF65-1)

Comment: In general, NextGen strongly supports the re-adoption of the Low Carbon Fuel Standard through 2030. (NEXTGEN3_FF65-2)

> **Agency Response:** Staff appreciates the commenters' support for the LCFS and the specific modifications to the proposed amendments described in the comments above.

C. Definitions

C-1. *Definition of Fuels*

C-1.1. *Biomass-Based Diesel and Renewable Hydrocarbon Diesel*

Comment: We suggest staff review the proposed changes to the definition of Biomass-based Diesel (18) and Renewable Hydrocarbon Diesel (112). In the case of the former, the proposal strips the definition down to below utilitarian – some reference or recognition of the existing definition of biodiesel, such as "biodiesel, as defined in (8)" (should 8 ultimately be the actual number for the biodiesel definition) is appropriate and the reference to renewable diesel is potentially misleading since, in the case of the latter (112) the phrase "Renewable Hydrocarbon Diesel" is used. We believe the reference to renewable diesel should be changed to "renewable hydrocarbon diesel." To provide continuity (REG3_FF44-3)

> **Agency Response:** The proposed definition of Biomass-based Diesel was revised as intended. Using the term "Renewable Hydrocarbon Diesel" in the Biomass-based Diesel definition may provide continuity with the "Renewable Hydrocarbon Diesel" definition. However, "Renewable Diesel" is used throughout the LCFS and it is understood commonly that Renewable Diesel is the same as Renewable Hydrocarbon Diesel.

C-1.2. *Renewable Propane*

Comment: REG supports the updated definition of Renewable Propane though we'd recommend changing the acronym from LGP to LPG as this is the commonly accepted acronym. (REG3_FF44-2)

> **Agency Response:** Staff appreciates the support on the updated definition of Renewable Propane. The acronym for liquefied petroleum gas is changed to LPG.

C-1.3. *Definition of "Biomethane"*

C-1.3a. *Support for the Modification to the Definition of "Biomethane"*

Comment: Page 4: The Task Force thanks CARB for specifying that the definition of "biomethane," also referred to as "renewable natural gas," will include gas produced from feedstocks such as the organic portion of municipal solid waste. (TASKFORCE2_FF7-3)

> **Agency Response:** Staff appreciates the commenter's support for the amended definition.

C-1.3b. Multiple Comments: *Definition of "Biomethane" is too Limited*

Comment: Page 4: The previous version of the amendments proposed to expand the definition of "biomethane," also referred to as "renewable natural gas," in Section 95481 of the Health and Safety Code to include synthetic natural gas derived from renewable resources and changed the description of the fuel to simply one that "meets pipeline quality natural gas standards." The modifications to the amendments change the definition of "biomethane" to mean a synthetic natural gas derived from renewable resources "which has been upgraded for use in natural gas vehicles." The definition of "biomethane" should not be limited to fuels upgraded for use in natural gas vehicles only. The definition of "biomethane" should include any natural gas derived from renewable resources regardless of its end use. (TASKFORCE2_FF7-2)

Comment: The definition of biomethane in § 95481(a)(19) states that "Biomethane means methane… which has been upgraded for use in natural gas vehicles." Narrowly defining biomethane as methane upgraded for use in natural gas vehicles limits the potential to use biomethane in other fueling applications and fuel production activities, including, but not limited to the following:

- Renewable electricity generation
- Renewable hydrogen production
- Use as process energy for fuel production

We believe that it is CARB's intention to keep the definition of biomethane broader. For example, in § 95481(a)(113), renewable hydrogen is defined as "hydrogen derived from… catalytic cracking or steam methane reforming of biomethane."

<u>Recommended Action:</u> We recommend that the definition of biomethane in § 95481(a)(19) be changed to "Biomethane means methane derived from biogas or synthetic natural gas derived from renewable sources, including the organic portion of municipal solid waste. Biomethane contains all of the environmental attributes associated with biogas and can also be referred to as renewable natural gas." (ECOENGINEERS2_FF21-1)

Comment: Iogen has a concern with the update to the definition of "biomethane" and how this may impact renewable hydrogen. As defined in the LCFS, "renewable hydrogen means hydrogen derived from (1) electrolysis of water or aqueous solutions using renewable electricity; (2) catalytic cracking or steam methane reforming of biomethane; or (3) thermochemical conversion of biomass, including the organic portion of municipal solid waste (MSW).

The definition of biomethane is proposed to be updated to "Biomethane means methane derived from biogas, or synthetic natural gas derived from renewable resources, including the organic portion of municipal solid waste, gas which has been upgraded for use in natural gas vehicles"

Iogen is concerned that while renewable hydrogen must be derived from biomethane, the updated definition of biomethane seems to only include gas which is being used in natural gas vehicles, thereby precluding biomethane to be used for the production of renewable hydrogen. Iogen suggests that the definition of biomethane should be updated to include any qualifying transportation fuel. Iogen's suggested fix would be to update the definition of biomethane to:

- "Biomethane" means methane derived from biogas, or synthetic natural gas derived from renewable resources, including the organic portion of municipal solid waste, gas which has been upgraded to meet pipeline quality natural gas standards, for use in natural gas vehicles, or for use in producing renewable hydrogen."

This definition includes pipeline book and trade transfers of pipeline quality gas and any direct feeding of biogas to refineries for renewable hydrogen production (which should in in the interest of the LCFS). (IOGEN1_FF36-2)

Comment: 1. Regarding the addition of Section 95488.9(f), Carbon Intensities that Reflect Avoided Methane Emissions from Dairy and Swine Manure or Organic Waste Diverted from Landfill Disposal:

….

b. However, the section repeatedly uses "biomethane" to define the eligible project types. According the definitions section 95481 (a) (19), "Biomethane" is biogas…. "which has been upgraded for use in natural gas vehicles." This definition is extremely problematic since it could be interpreted to state that only biogas used in natural gas vehicles is eligible for claiming avoided methane benefits. As the rule makes clear in many places, biogas can be used to create biofuels such as biodiesel and ethanol, or hydrogen fuels. According to the proposed language, none of these uses might be eligible to claim avoided methane benefits.

c. We do not believe it was ARB's intention to only allow natural gas vehicle projects to claim avoided methane benefits, since liquid biofuel and hydrogen production are other valuable uses of dairy biogas that the Rule seeks to promote. We strongly suggest that either section 95488.9(f) remove all references to biomethane (using "biogas" instead), or else the definition of biomethane be changed in 95481(a)(19) to a define biomethane as any biogas that is upgraded for use in the production of transportation fuels. We believe the latter option is superior, since "biomethane" is used throughout the Rule in contexts that do not limit themselves to natural gas vehicles only. (MEW1_FF40-2)

Comment: b. Biogas or biomethane can be used create a variety of biofuels. Calgren Renewable Fuels plans to use biomethane from a dairy digester cluster to produce ethanol and biodiesel. The new proposed definition of biomethane 95481(a)(19) states "Biomethane" is a biogas..."which has been upgraded for use in natural gas vehicles." The definition could be interpreted to state that biomethane can only be used to create CNG or LNG. It is our understanding that these fuels should be allowed to claim

avoided methane benefits for any and all biofuel production. Various uses for biomethane will be used by Calgren as input to make low carbon fuels. (CRF2_FF42-6)

Comment: RNG Coalition supported staff's previous proposed definition of biomethane, which was consistent with California Health and Safety Code Section 25420, which states that biomethane means biogas that meets the standards for injection into a common carrier pipeline. However, RNG Coalition also expressed concern to staff that this definition alone would not allow for onsite fueling, and therefore suggested the addition of a second definition to allow for the use of biogas that has been upgraded to natural gas vehicle fuel standards.

However, the manner in which staff has attempted to address the issue in the proposed modifications puts the regulation in conflict with state law. The proposed definition defines biomethane as biogas that has been upgraded for use in a natural gas vehicle. However, biogas that has been upgraded for use in a natural gas vehicle does not necessarily meet standards for injection into a common carrier pipeline. We believe this may cause confusion between various programs that use the definition in the Health and Safety Code. We also believe this would be inconsistent with other sections in this regulation, for example, RNG used as a process fuel or for use in book-and-claim accounting may require the use of biomethane that meets the standard used in state law. **Therefore, we respectfully ask that you either (1) adopt the statutory definition of biomethane and account for vehicle fuel in a separate definition, or (2) revise the proposed definition as follows: *Biomethane is biogas which has been upgraded to natural gas quality standards, including but not limited to vehicle fuel and pipeline injection standards*.** (RNGC3_FF46-3)

> **Agency Response:** In response to these comments, the definition of biomethane was modified. Please refer to Responses C-1.4b through C-1.4d, Definition of "Biomethane," in Chapter IV.

C-2. *ASTM Specification Reference*

Comment: Throughout the Definitions, it appears that all references to ASTM specifications have been deleted in the 15-day Modifications. WSPA would prefer that the ASTM Specifications references be retained in the regulation as an example (not a compliance citation) of a known standard for various fuel types. A reference to "the most current version" would suffice to avoid the references becoming outdated. (WSPA5_FF19-1)

> **Agency Response:** Staff removed the ASTM specifications previously incorporated by reference in the definition of fuels as the ASTM specifications did not add any additional information to clearly identify the fuel type, and their inclusion may result in unnecessary duplication of requirements. The removal of ASTM specifications also avoids potential confusion from referencing outdated specifications.

C-3. Multiple Comments: *Definition of "Green Tariff"*

Comment: San Francisco had requested in its initial comments that:

….

- the definition for the term "Green Tariff" also be clarified to include all zero-CI, RPS-eligible resources.

….

<u>The proposed definition of "Green Tariff" is also inconsistent with California law defining Zero-CI, RPS-eligible resources</u>

The proposed definition for the term "Green Tariff" should be reconciled in a similar manner as described above. Similar to Section 95488.1(b)(2)(A), the proposed definition of a "Green Tariff" refers to "low-carbon intensity energy resources, including solar photovoltaic, wind, solar thermal, electricity generated from a small hydroelectric facility of 30 megawatts or less, ocean wave, ocean thermal, and tidal current." This language continues to exclude other zero-CI energy resources, specifically those zero-CI, RPS-eligible resources identified in Public Utilities Code Sections 399.12 and 399.12.5.

The regulation's proposed definition for the term "Green Tariff" also includes "the Green Tariff Shared Renewables [GTSR] program … defined under the California Public Utilities Code sections 2831-2833."[8] The GTSR program defines an "Eligible renewable energy resource" and other related terms as having "the same meaning as those terms have for the California RPS Standard Program" starting at "Article 16 (commencing with Section 399.11)" of the Public Utilities Code.[9]

[8] Proposed Section 95481(a)(61).

[9] Public Utilities Code Section 2831.5(b)(1).

Therefore, both the definition of the term "Green Tariff" (proposed Section 95481(a)(61)) and the list of resources eligible for the Lookup Table Pathway (proposed Section 95488.1(b)) should be revised to be internally consistent and consistent with California law regarding RPS-eligibility. San Francisco has proposed revisions in Attachment A.

….

§95481. Definitions and Acronyms.

(a) *Definitions.*

(61) "Green Tariff" means a program in which a retail seller of electricity offers its customers an opportunity to purchase a portfolio of energy sourced from low-carbon intensity energy resources, including solar photovoltaic, wind, solar thermal, electricity generated from a small hydroelectric facility of 30 megawatts or less, <u>hydroelectric facilities meeting the requirements of Public Utilities Code sections 399.12 or 399.12.5,</u>

ocean wave, ocean thermal, and tidal current. This includes resources eligible under the Green Tariff Shared Renewables program, excluding geothermal and biomass, established pursuant to California Senate Bill 43 (2013) and defined under the California Public Utilities Code sections 2831-2833.

*****

(CCSF3_FF51-3)

> **Agency Response:** In response to this comment and others expressing confusion about the meaning of renewable and low-CI electricity resources, staff modified the definition of "green tariff" and added a definition of "low-carbon intensity (low-CI) electricity." The low-CI electricity definition states that it includes RPS-eligible resources, and in the definition of green tariff, the list of examples is removed to avoid confusion, inconsistency, and unintentional exclusion. Please also refer to Response D-6.2. in Chapter IV.

D. Fuels Subject to the Regulation

D-1. *Alternative Jet Fuel*

D-1.1. Multiple Comments: *Support for the Proposed Modifications to the Alternative Jet Fuel Provisions in the Low Carbon Fuel Standard*

Comment: On behalf of United Airlines, this letter is to express our strong support for inclusion of alternative jet fuel (AJF) within the Low Carbon Fuel Standard (LCFS), as proposed in your Final Proposed Modifications document released June 20, 2018. As you know well, United has strongly supported inclusion of AJF in the LCFS.

Specifically, we greatly appreciate your attention to the carbon intensity (CI) benchmark for conventional jet fuel, and your adoption of a static baseline for conventional jet fuel until 2023, at which point it will be adjusted in parity with the diesel baseline. As we noted and you acknowledged, this change would avoid having AJF continue to be disincentivized despite being included in the LCFS.

Your attention to this matter, and your staff's work to resolve this issue has been most welcome. The benchmark set forth in your most recent document release better reflects the true CI of conventional jet fuel, while also balancing your policy needs for AJF not having a greater LCFS credit than renewable diesel.

As currently proposed, the CI score and the resulting credits allowed for AJF will help incentivize production and contribute to greater use of the alternative fuel. United Airlines is grateful for your work and your efforts on this matter. (UNITED2-FF13-1)

Comment: As we noted in our previous comments,[2] A4A and its member airlines strongly support the inclusion of alternative jet fuel (AJF) as an eligible credit-generating fuel on an opt-in basis. In addition, we strongly support the modifications CARB has now proposed to the carbon intensity values for jet fuel in Section 95484(d) of the LCFS regulations because they more reasonably reflect the carbon emissions associated with this fuel and accord it similar treatment to diesel fuel over time. This will help provide needed regulatory incentives for AJF, which in turn will support the developing California advanced biofuels industry, lower the cost of compliance for obligated parties, and advance the State's environmental goals.

[2] We incorporate our previous comments, "Comments on the 2018 Amendments to the Low Carbon Fuel Standard" (April 23, 2018), by reference here.

In our comments on the LCFS revisions CARB originally proposed, A4A detailed the reasons why the decreasing carbon intensity benchmarks for jet fuel were unreasonably aggressive, both as a technical and policy matter. We greatly appreciate CARB's consideration of and response to those comments. While A4A still believes CARB would be justified in using a fully static carbon intensity benchmark for jet fuel as we noted in our original comments, we support CARB's proposal in Section 95484(d) of the LCFS regulations to adopt a baseline for jet fuel that will remain static until 2023, when the diesel carbon intensity benchmark reaches the jet fuel baseline, at which time the jet fuel carbon intensity benchmarks will be adjusted in parity with the diesel carbon

intensity benchmarks. As A4A explained in our earlier comments, not only is this approach supportable as a technical matter, it will help incentivize AJF production, which will in turn stimulate additional renewable diesel production as diesel is necessarily coproduced with AJF, often with diesel in a much higher ratio. At the same time, this approach addresses CARB's preference that AJF not command a greater LCFS credit than renewable diesel or otherwise incentivize AJF at the expense of renewable diesel. As explained in our comments on the original proposal, even with crediting parity for AJF and renewable diesel under the LCFS, renewable diesel will continue to maintain a significant market advantage over AJF due to various State and federal policy structures and fuel production factors.

In sum, the approach CARB has proposed for AJF to be eligible as a credit-generating fuel under the LCFS and the carbon intensity curve now proposed for jet fuel will help incentivize AJF production, lower LCFS compliance costs and advance the State's environmental goals, while not only preserving but further enhancing renewable diesel production. Accordingly, we strongly support CARB's proposal and urge CARB to adopt it. (A4A2_FF15-1)

Comment: This comment supersedes our comment submitted April 23, 2018, as the revised version of the LCFS Regulation released June 20, 2018 (the "LCFS Proposal") resolved specific concerns that we raised in our prior comment letter regarding crediting issues. We now strongly support all aspects of the LCFS Proposal pertaining to AJF.

…

<u>Strong Support for LCFS Proposal</u>

This letter expresses our strong support for the inclusion of AJF in the LCFS, and of ARB's specific regulatory proposals to facilitate LCFS credit generation through opt-in participation for AJF uplifted in California. We acknowledge and appreciate the exemplary work of ARB staff and management in working with the AJF Producers, A4A, and the aviation industry. We have been cooperatively working with ARB for two years in the development of this rule. Throughout this time, we have communicated steadily through numerous public workshops, meetings, informal written comments, phone calls, and emails. ARB has been actively engaged throughout this process and has thoroughly considered and integrated our input into the proposed rule. We heartily recommend adoption of the AJF regulatory proposal as proposed and concur with the specifics of the proposed regulatory structure pertaining to the rule.

The LCFS has proven to be an effective, market-based program that has driven the development and expanded the supply of low carbon fuels in California. By including low carbon alternative jet fuels in the program, ARB will further expand the supply of less carbon-intense fuels and facilitate attainment of California's greenhouse gas ("GHG") reduction policies. By sending a clear and long-term market signal that AJF is eligible to generate LCFS credits in addition to Renewable Fuel Standard ("RFS") credits ("RINs"), ARB is facilitating investment and development in the decarbonization of the aviation sector. This pioneering work by California is crucial given the anticipated

growth of the aviation sector, and the technical and energy intensive demands of this sector.

Revised Carbon Intensity Benchmarks for AJF Crediting

The primary issue raised by our letter of April 23, 2018, and further described in a Power Point presentation delivered at the April 27th Board hearing pertained to the carbon intensity ("CI") benchmarks contained in Table 3 of the LCFS Proposal. These CI benchmarks determine the level of credit generation that qualifying AJF will be eligible generate pursuant to the LCFS program. The changes to Table 3 that ARB made in the LCFS Proposal were responsive to the specific concern we expressed in prior comments. Our concern was that the LCFS CI benchmarks contained in the prior version of Table 3 would have significantly dis-incentivized AJF production as compared to production of on-road renewable diesel fuel. However, with the changes that ARB has proposed to Table 3, the LCFS program will provide crediting parity to AJF beginning in 2023 and in subsequent years. We are therefore in strong support of the revised CI benchmarks contained in Table 3.

Economic Factors Applicable to the AJF Market

While the revised Table 3 establishes crediting parity under the LCFS, we think it important to note that renewable diesel remains significantly favored over AJF by a number of other California and federal policy structures, as well as by market factors. These policy and market factors pose challenges to the commercialization of AJF, and establish that the integration of AJF into the LCFS does not pose a risk of incentivizing production facilities that currently produce renewable diesel to switch to AJF production. These factors are discussed in more detail in our previously submitted letter of April 23, 2018 but are here summarized as they remain relevant to policy design issues regarding the inclusion of AJF in the LCFS.

1. Producers forecast less revenue from sales of alternative jet fuel than renewable diesel because jet fuel has historically sold at a discount to on-road diesel in the California market. Future projections predict this trend will continue.
2. Due to the more stringent cold flow specification for jet fuel, alternative jet fuel requires more intensive processing than does on-road renewable diesel. Petroleum jet is relatively less burdened in meeting the jet specifications due to the inherent differences between fossil crude feedstocks and renewable jet feedstocks.
3. Jet fuel is not burdened at the rack by the cost of cap and trade allowances as is petroleum diesel. In today's market, this provides renewable diesel with an effective .15/gallon price discount to petroleum diesel that alternative jet fuel will not receive.
4. Conventional jet fuel pricing is also not burdened with the LCFS compliance cost that is assessed at the rack for conventional diesel fuel resulting in an effective .07/gallon price discount to petroleum diesel in today's market that alternative jet fuel will not receive.

5. Under the federal Renewable Fuel Standard (RFS), AJF receives relatively fewer RINs than on-road diesel with renewable diesel generating 1.7 RINs per gallon and renewable jet fuel generating 1.6 RINs per gallon. This results in a 6% discount on RIN generation representing .06/gallon less incentive per gallon in today's market. (AJFP4_FF29-1)

Comment: REG supports the clarified language on alternative jet fuel in (a)(1)(C)… (REG3_FF44-5)

Comment: REG supports the updated benchmark for alternative jet fuel. We believe this update will provide the correct level in invitation to encourage the production of alternative jet fuel. (REG3_FF44-8)

> **Agency Response:** Staff appreciates the continued support for including alternative jet fuel in the LCFS program as an opt-in credit-generating fuel. Staff also appreciates the support for the proposed modifications to the original alternative jet fuel proposal, including updates to the carbon intensity (CI) benchmark for conventional jet fuel and change to a static baseline for conventional jet fuel until 2023.

D-2. *Propane*

D-2.1. *Support for Proposed Modifications to the Propane Provisions*

Comment: WPGA strongly supports the inclusion of propane as a fuel under the LCFS. We appreciate that Staff has worked with us over the last several months to help ensure that propane receives fair and equitable treatment as it is added into the regulation. (WPGA3_FF58-1)

> **Agency Response:** Staff appreciates the support for the proposed inclusion of propane in LCFS.

D-2.2. *Energy Economy Ratio for Propane*

D-2.2a. *Energy Economy Ratio for Indoor Forklifts*

Comment: 1. The Correct Baseline for Indoor Propane Forklifts Should be Gasoline SI Engines, not Diesel CI Engines

<u>Summary of Specific Concerns</u>

Under the LCFS, CARB assumes diesel-fueled compression ignition engines are the baseline for all off-road equipment. In reality, indoor forklifts (and many other small off-road applications) are dominated by spark-ignition engines, including those fueled by propane and gasoline. This is very important, given that spark-ignition propane and gasoline engines are at parity for their EERs. Since gasoline is already an established baseline fuel in the LCFS (and propane is not), WPGA strongly believes that gasoline

should be the baseline for indoor forklifts, and propane forklifts should therefore be assigned an EER of 1.0, instead of 0.9.

Below, we summarize WPGA's rationale and supporting evidence for this important point.

- Forklifts should be categorized as either primarily outdoor applications (railyard and shipyard applications) or primarily indoor applications (warehouse use). Specifically, we recommend delineating Class IV for indoor use, with gasoline serving as the baseline fuel instead of diesel. Most indoor-only applications are typically Class IV (cushion tire) lift trucks in the 3,000 to 7,000+ lbs. capacity range. This is due to the generally smaller sizes offered on a Class IV unit, and the fact that the indoor surfaces they're working on are wholly flat/smooth and pose no risk to the tire as they would on a Class V pneumatic tire lift truck.
- By comparison, diesel forklifts not used for <u>indoor</u> applications such as warehouses, owing primarily to the exhaust emissions of diesel engines (especially diesel particulate matter, a CARB-declared toxic air contaminant). In addition, diesel forklifts have higher sound levels and are generally designed for higher horse power uses. These are all reasons why diesel forklifts are not used in primarily indoor applications and should therefore not be considered as the baseline for such applications.
    - Many OEMs sell Class IV indoor lift trucks that operate on gasoline or propane (but not diesel); examples include the following:
    - <u>Mitsubishi FGC15N-FGC33N</u> lift trucks.
    - <u>Caterpillar GC20-33NY</u> and <u>GC35-70K</u> lift trucks.
    - <u>UniCarriers Platinum</u> II series lift trucks.
    - <u>Clark Material Handling S20-32C</u>, <u>CGC 40-55</u>, <u>GEN 2 C20C-32C</u>, <u>GEN 2 C15C-20SC</u>
    - <u>Toyota Forklifts</u> (FYI, the "Box Car Special" models are their most popular).
    - <u>Crown C-5</u> cushion tire and <u>C-G</u> cushion tire lift trucks.
    - <u>CombiLift C-Series</u>
- We believe that CARB's 2014 ISOR for the LCFS program supports the conclusion that gasoline should be the baseline for smaller indoor-optimal forklifts. In the ISOR, which documented the initial inclusion of electric forklifts into the LCFS,[2] CARB refers to a 2003 study by EPRI. That EPRI report[3] notes that the analysis was conducted ***only*** on 4-wheel rider class forklifts (primarily Class I). Additionally, the ISOR references populations of Class I to III electric forklifts in its assessment. This strongly suggests that the basis of the analysis was for forklifts that are operated indoors, partially indoors, or are otherwise compelled to use low-emitting engines/technologies. In this case, it is

reasonable to assume that spark-ignited engines are the true baseline, and propane forklifts using such engines should be assigned an EER of 1.0.

[2] See https://www.arb.ca.gov/regact/2015/lcfs2015/lcfs15isor.pdf, page III-9.

[3] See https://www.epri.com/#/pages/product/1002230/?lang=en.

- Diesel forklifts -- particularly larger, rough-terrain forklifts (Class VII) -- will now be captured under the "Cargo Handling Equipment" (CHE) category, as described in the proposed 2018 modifications to the LCFS. These modifications establish an EER for electric CHE that is inclusive of heavy-lift diesel forklifts.[4] Because diesel forklifts are captured in the CHE category, the category called "forklifts" should refer to indoor, or indoor/outdoor operating forklifts with the assumption that the baseline is spark-ignited ICE technology.

  [3] See https://www.arb.ca.gov/regact/2018/lcfs18/15dayattd.pdf.

Recommended Staff Actions

WPGA respectfully asks CARB to designate gasoline as the baseline fuel for all Class IV forklifts, which are designed primarily for indoor use, and assign propane-powered forklifts in this application with an EER of 1.0. (The same would apply to any other spark-ignited ICE technologies powering Class IV forklifts.)

…

In conclusion, the Western Propane Gas Association supports inclusion of propane in the LCFS, with critical updates to the propane carbon intensity value and baseline for indoor forklifts. We respectfully ask that Staff take the following actions, to make the regulation as accurate as possible with respect to how California's transportation propane is produced and utilized:

- Designate gasoline as the baseline fuel for all Class IV forklifts, which are designed primarily for indoor use, and assign propane-powered forklifts in this application (or any other spark-ignited ICE technologies) with an EER of 1.0. (WPGA3_FF58-2)

  Agency Response: Please see Response D-2.3a in Chapter IV on Energy Economy Ratio for Indoor Forklifts.

D-2.2b. *On-Road Trucks and Buses Displace Gasoline*

Comment: 3. Propane On-Road Trucks and Buses Primarily Displace Gasoline, Not Diesel

Summary of Specific Concerns

Propane vehicles in CA operate in several market niches in medium-duty applications. Airport shuttle bus, school bus, and transit bus fleet operators routinely choose not to purchase diesel vehicles, for a number of reasons. It is well known that 2010 on-road diesel tailpipe emission standards have resulted in greater diesel vehicle purchase and repair costs, and with reduced duty-cycle flexibility (particularly in stop-and-go settings

and lower load or temperature profiles that can lead to DPF failure). Airport shuttles routinely operate in in highly competitive, contracted settings where higher diesel vehicle and repair costs are simply not tolerated. In addition, shuttles and buses routinely operate in areas sensitive to diesel exhaust exposure, including multi-level airport structures and with daily transporting school children between home, school, and offsite school events. Public transit operations have similarly rejected use of diesel vehicles, purchasing lower-emitting propane or other alternatively-fueled bus options[6].

[6] San Diego Metro Transit System operates 77 propane buses; according to MTS' Michael Wygant, diesel buses were simply not a viable option.

Propane vehicles primarily compete in the Class 4-6 markets, where they displace gasoline fuel used in such vehicles. This is contrary to CARB LCFS staff's assumption that all heavy-duty (≥ 14,000 lb. GVWR) on-road vehicles in CA will operate as diesel vehicles. We invite Staff to review our previously submitted comments on the displacement of gasoline by propane vehicles, as well as the photos provided at the end of this letter.

Recommended Staff Actions

Because of the discrepancies in diesel, gasoline, and propane heavy-duty vehicle EER values proposed by CARB staff, we recommend CARB to add a Class 4-6 option for propane vehicles displacing gasoline, not diesel. We look forward to continuing our dialog on this matter per initial conversations with CARB staff in June, 2018.

…

We respectfully ask that Staff take the following actions, to make the regulation as accurate as possible with respect to how California's transportation propane is produced and utilized:

…

- Add a Class 4-6 option for propane vehicles displacing gasoline, with an EER value of 1.0. (WPGA3_FF58-4)

  Agency Response: Please see Response D-2.3b in Chapter IV.

D-2.2c. *Propane Displaces Gasoline, Not Diesel*

Comment: However, because propane engines are based on spark-ignition gasoline engines (and many are converted from gasoline engines), it is more appropriate to use an EER of 1.0 because the vehicles and equipment using propane are displacing gasoline. That would push the first year of deficit generation and mandatory compliance for small fueling stations out to 2027 rather than 2021 as proposed by ARB staff. (WSPA5_FF19-3)

Agency Response: Please see Responses D-2.3b and D-2.2 in Chapter IV.

D-2.2d. ***EER Determination for LPG Buses***

Comment:

Vehicle Type	EER published in ARB ISOR	EER in Appendix A of the June 20th ARB Proposal	Suggested Correction in H-D System Report
LPG Bus	0.9	0.9	0.74 at urban speeds (<20 mph)

(GROWTHENERGY2_FF56-79)

Agency Response: Please see Response D-2.3c in Chapter IV.

D-3. ***Fossil Compressed Natural Gas***

D-3.1. ***Support for the Proposed Modifications to the Fossil CNG Provisions***

Comment: The 15-day Modifications propose to limit the small station exemption for fossil CNG and propane until these fuels first begin to generate LCFS deficits. In performing the calculation, an Energy Economy Ratio (EER) of 0.9 was used, reflective of fuels used as a diesel replacement. This is appropriate for CNG as most on-road applications are in the heavy-duty sector (e.g., buses, Class 8 tractors, refuse haulers, etc.). (WSPA5_FF19-2)

Agency Response: Staff appreciates the commenter's support for the use of 0.9 EER for performing the calculation to propose an exemption for small fossil CNG stations from LCFS mandatory reporting requirement.

D-3.2. Multiple Comments: ***Exemption and Phase-in Period for Removal of Opt-in status for Small Station Dispensing Fossil CNG***

Comment: LADWP appreciates ARB's proposal to exempt small fossil compressed natural gas (CNG) stations with 50,000 gasoline gallon equivalent (GGE) or less annual throughput from the LCFS until the fuel starts generating deficits, because LADWP is a CNG fuel provider with a limited number of consumers. However, LADWP does not agree with Staff that "the potential benefit of reporting and generating credits for 50,000 GGE or more of CNG or propane in the LCFS would most likely outweigh the cost of participating in the program." Using 2017 numbers, the amount of credits generated by 50,000 GGE of CNG dispensed equates to less than 100 LCFS credits. The benefit at this level does not outweigh the cost and time required to complete the third-party verification process as required for participating in the LCFS program.

LADWP recommends ARB increase the limit for the exemption to 150,000 GGE or less annual throughput from each station. The requirement for mandatory reporting and

third-party verification, and cost burden associated with the proposed compliance obligations will likely hinder future investments in alternative fuel vehicles. Alternatively, an exemption can be added to section 95500, similar to section 95500(b)(2)(B) Deferred Verification, where the CNG fuel pathway is exempt from verification if the quantity of fuel produced and reported by any entity does not result in more than 2,000[1] credits generated in LRT-CBTS during the prior calendar year.

[1] One-third of the limit in section 95500(b)(2)(B).

(LADWP2_FF10-2)

Comment: As stated in our previous comment letter dated April 23, 2018, SoCalGas is concerned with requiring fossil compressed natural gas (CNG) to report into the program starting in 2019, when fossil CNG is expected to remain a credit generating fuel until 2024. SoCalGas remains concerned that the administrative requirements would be overly burdensome for small users, who have yet to opt-in to the program. Our fear is that these users would prefer to move to petroleum based fuel instead of dealing with the administration.

SoCalGas previously recommended providing an exemption for small compressed natural gas (CNG) station operators that have not yet opted in to the LCFS Program and dispense less than 1.25 million gasoline gallon equivalent units until fossil CNG becomes a deficit generating fuel in 2025. The purpose of the exemption would be to retain existing fossil CNG users, give them time to become comfortable or find assistance with the administrative burden, and eventually move them to renewable gas.

In response, in the Modified Text for the Proposed Amendments, CARB staff included an exemption for propane and fossil CNG users that use less than 50,000 gge/year, which is a fraction of what was originally recommended. CARB staff explained that all fuels should be treated equally and since the propane industry requested an exemption of 50,000 gge/year, to be equitable, fossil CNG should be provided the same exemption threshold.

SoCalGas agrees with CARB staff that all fuels should be treated equitably. Equity for all fuel types is key to maintaining the integrity of the program. Propane, which is currently a credit generating fuel is expected to become a deficit generating fuel in 2021. Per the proposed LCFS Amendments, Propane would be required to begin reporting fuel to the LCFS program in 2019, *two years* before becoming a deficit generating fuel. The proposed Amendments would also require fossil CNG begin reporting in 2019, *five years* before becoming a deficit generating fuel.

SoCalGas recommends that CARB maintain equity between all fuels. This can be achieved by delaying the implementation of reporting for fossil CNG until 2022, *two years* before becoming a deficit generating fuel, similar to what is required for propane. This modification would achieve the goals of the exemption, outlined above and would not impact emission reductions achieved. (SCG3_FF26-1)

Comment: RNG Coalition believes that equity for all fuel types is key to maintaining the integrity of the LCFS program. Propane, which is currently a credit generating fuel,

is expected to become a deficit generating fuel in 2021. Under the proposed LCFS Amendments, propane would be required to begin reporting fuel to the LCFS program in 2019, *two years* before becoming a deficit generating fuel. The proposed Amendments would require fossil CNG to begin reporting in 2019, *five years* before becoming a deficit generating fuel. RNG Coalition is concerned that this implementation timeline will not provide sufficient time for these users to secure RNG contracts and may unintentionally lead some fleet owners to switch back to using diesel trucks to avoid the reporting requirement. In order to maintain equity between fuels, and in order to avoid backsliding on alternative fuels, **we respectfully ask that you consider delaying the implementation of reporting for fossil CNG until 2022, *two years* before becoming a deficit generating fuel and consistent with the timeline associated with propane.** (RNGC3_FF46-11)

Comment: Delay implementation of reporting for fossil CNG

It is important to emphasize the benefits and support for diversifying California`s fuel sources. That being said, the LCFS should strive to regulate the use of fuel types equally and when applicable, uniformly. The proposed amendments by the staff would cause a discrepancy between different fuel types. The reporting requirement for fossil CNG unfairly sets a different requirement than that of propane. A different timeline for fuels that become deficit generating can cause confusion when trying to follow the regulations set by the Board and does not give an ample amount of time for users and fleet owners to switch to cleaner alternatives. If not given enough time could lead fleet owners to adopt diesel trucks if not given enough time to invest and plan in the cleanest technology available. (CNGVC3_FF59-3)

Comment: Page 9: Section 95482 of the Health and Safety Code has been modified to exempt small fossil compressed natural gas (CNG) fueling stations from LCFS requirements until the respective fuels become deficit generating to allow small station operators to participate in the LCFS. Page II-6 of the Staff Report proposed to remove the opt-in status of fossil compressed natural gas (CNG). The biogas market has significant potential to expand over the next few years due to the organic waste disposal reduction mandated by Senate Bill 1383 (Chapter 395 of the 2016 State Statutes) and its implementing regulation, which focuses on anaerobic digestion (AD) technologies and processes to generate biogas and biomethane. Additionally, as monetary incentives for biomethane pipeline infrastructure projects become available pursuant to Assembly Bill 2313 (Chapter 571 of the 2016 State Statutes), it is important that the existing infrastructure for natural gas be properly maintained to provide short-term storage for biomethane and increase access to biomethane for transportation fleets and other end users. As such, the Task Force strongly believes that CARB needs to extend the phase-out of all fossil CNG, not limited to small fueling stations, to allow the biogas market to expand to make use of the existing infrastructure and avoid discouraging investments in gas pipeline infrastructure until additional in-state infrastructure is developed to provide for the state's needed renewable CNG. (TASKFORCE2_FF7-4)

Agency Response: Please see Response D-3.1, Exemption and Phase-In Period for Removal of Opt-In Status for Small Station Dispensing Fossil Compressed Natural Gas, in Chapter IV.

In further response to TASKFORCE2_FF7-4, staff believes most of the larger CNG stations in California are already reporting in the program. Moreover, requiring larger fossil CNG stations to report in the program before the fuel becomes deficit generating provides stations the opportunity to generate credits in the program, which can be used for developing reporting capabilities and necessary infrastructure to minimize the risk of non-compliance when the fuel becomes deficit generating.

D-4. *Renewable Natural Gas*

D-4-1. *Support for the Proposed Modifications to the Renewable Natural Gas Provisions*

D-4.1a. *Support for Renewable Natural Gas*

Comment: AECA appreciates and supports recent revisions to the proposed LCFS amendments that adequately address some of our initial comments and concerns, including the following:

1) Extension of environmental attribute claims from two to three calendar quarters
2) Allowance for a temporary CI for dairy biomethane at -150
3) Development of a Tier 1 pathway calculation for dairy biomethane (AECA3_FF35-1)

Agency Response: Staff appreciates the commenter's support for the modifications and Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure.

D-4.1b. Multiple Comments: *Support for Dairy and Swine Manure Crediting*

Comment: EcoEngineers commends CARB on its vision to incentivize avoided methane emissions for biomethane from dairy and swine manure. (ECOENGINEERS2_FF21-5a)

Comment: Bluesource commends CARB on its vision to incentivize avoided methane emissions for biomethane from dairy and swine manure. (BLUESOURCE1_FF70-6a)

Comment: 1. Regarding the addition of Section 95488.9(f), Carbon Intensities that Reflect Avoided Methane Emissions from Dairy and Swine Manure or Organic Waste Diverted from Landfill Disposal:

a. We support the addition of this section since it will accurately value the avoided methane benefits of dairy digesters. (MEW1_FF40-1)

Agency Response: Staff appreciates the commenters' support for the proposed amendments related to avoided methane emissions from dairy and swine manure biomethane.

D-4.1c. Multiple Comments: ***Support the Proposed Limit for Indirect Book-and-Claim Accounting of Renewable Natural Gas***

Comment: DTEBE thanks CARB for the amended language in 95488.8(h)(i)(2)(A) that allows RNG injected into the pipeline system three calendar quarters from injection to be used as vehicle fuel in California. DTEBE believes this is a reasonable amount of time to generate environmental attributes during normal operations. (DTEBE2_FF20-4)

Comment: RNG Coalition supports the extension of the timeframe between the time that RNG can be injected into the common carrier pipeline in North America and the time that quantity is sold as RNG in California to three calendar quarters. We asked for this change in our previous comments and were pleased to see this in the proposed modifications. (RNGC3_FF46-5a)

Comment: Clean Energy appreciates staff's consideration of stakeholder feedback in the decision to extend the limitation on book-and-claim accounting to three quarters. (CE4_FF52-2a)

Comment: CalBio supports and greatly appreciate the change to expand the generation of LCFS credits from biomethane injected into the pipeline from two calendar quarters to three. (CALBIO1_FF67-1a)

Agency Response: Staff appreciates the commenters' support for proposed extension of the allowed period for transferring renewable attributes of pipeline-injected biomethane using book-and-claim accounting from two quarters to three quarters.

D-4.2. ***Dairy and Swine Manure Crediting***

D-4.2a. Multiple Comments***: Extend Initial Crediting Period to 20 or 30 Years***

Comment: Livestock operations that capture manure methane and convert it to renewable natural gas (RNG) vehicle fuel should be allowed to generate LCFS credits based on the methane capture and destruction for at least a 20-year period. The proposed regulation limits credit generation to 10 years in event of regulation of livestock emissions. We believe this would be counter-productive to meeting the goals of both SB 1383 and the LCFS. The 10-year limit necessarily compels investors and lenders to assume a 10-year cut off on the LCFS revenue that comes from avoided methane emissions, making the projects less attractive to finance and therefore more difficult to develop. The result will be fewer projects built, in the near term, that capture and use this RNG. If the regulation allows livestock RNG projects to count the avoided methane emissions for a minimum of 20 years, more projects will be funded and built and therefore more methane emissions will be avoided without regulation of those methane emissions. If the incentive is large enough, the methane capture will happen

irrespective of any future program that may limit or penalize these emissions. (BP2_FF8-4)

Comment: In addition, livestock operations that capture manure methane and convert it to renewable natural gas vehicle fuel should be allowed to generate LCFS credits based on the methane capture and destruction for at least 20 years. The proposed regulation limits credit generation to 10 years in event of regulation of livestock emissions and that will be counter-productive to meeting the goals of SB 1383 and the LCFS. (WSPA5_FF19-11)

Comment: Moreover, section §95488.9(f)(3)(B) states that the passage of "a law, regulation, or legally binding mandate requiring either greenhouse gas emission reductions from manure methane emissions from livestock and dairy projects or diversion of organic material from landfill disposal, comes into effect in California during a project's crediting period, then the project is only eligible to continue to receive LCFS credits for those greenhouse gas emission reductions for the remainder of the project's current crediting period. The project may not request any subsequent crediting periods." It appears to establish additionality requirements for projects and limit a project's crediting period.

We believe that it is in the best interest of the LCFS program to minimize regulatory uncertainty and allow projects that are built the full benefit of the regulations as they are today. The potential for future laws to destabilize project revenues disincentivizes project development.

<u>Recommended Action:</u>

…

2. Allow registered projects to be grandfathered and claim credits for the three 10-year crediting periods allowed during time of registration if a future law raises the baseline for additionality. (ECOENGINEERS2_FF21-6)

Comment: Moreover, section §95488.9(f)(3)(B) states that the passage of "a law, regulation, or legally binding mandate requiring either greenhouse gas emission reductions from manure methane emissions from livestock and dairy projects or diversion of organic material from landfill disposal, comes into effect in California during a project's crediting period, then the project is only eligible to continue to receive LCFS credits for those greenhouse gas emission reductions for the remainder of the project's current crediting period. The project may not request any subsequent crediting periods." It appears to establish additionality requirements for projects and limit a project's crediting period.

We believe that it is in the best interest of the LCFS program to minimize regulatory uncertainty and allow projects that are built the full benefit of the regulations as they are today. The potential for future laws to destabilize project revenues disincentivizes project development.

Recommended Action:

…

2. Allow registered projects to be grandfathered and claim credits for the crediting periods allowed during time of registration if a future law raises the baseline for additionality. (BLUESOURCE_FF70-7)

Comment: Senate Bill 1383 specifically directs CARB to adopt mechanisms and programs to spur dairy methane reduction opportunities in order to meet the state's ambitious methane reduction goals. AECA continues to strongly recommend that the proposed LCFS amendments specify that dairy biomethane projects be allowed one additional 10-year crediting period following any adopted dairy methane capture regulations. Specifying a second allowable crediting period will ensure the stable, long-term revenue streams needed by pipeline biomethane projects will be available to ensure long-term project viability. (AECA3_FF35-3)

Comment: The proposed regulation limits credit generation to ten years in the event of regulation of livestock emissions. RNG Coalition believes that this will be counter-productive to meeting the goals of SB 1383 and the LCFS. The ten-year limit necessarily compels investors and lenders to assume a ten-year cut off on the LCFS revenue that comes from avoided methane emissions, thus making projects less attractive to finance and develop. This will result in fewer projects being built in the near term that will capture and use the methane. If livestock RNG projects were allowed to count the avoided methane emissions notwithstanding future regulation, for at least 20 years, more projects would be funded and built and therefore more methane emissions would be avoided without regulation of those methane emissions. If the incentive is large enough, the desired level of methane capture would be achieved irrespective of any future regulation that would limit or penalize those emissions. **Therefore, we respectfully ask that you consider allowing livestock RNG projects to generate LCFS credits based on methane capture and destruction for at least 20 years.** (RNGC3_FF46-7)

Comment: ARB has added language to the LCFS regulation stating that if a regulation is passed mandating methane reductions from livestock manure, that dairy biomethane projects are only eligible to continue to receive LCFS credits for those GHG reductions for the remainder of its crediting period. This will prevent the project from being eligible to receive LCFS credits for subsequent crediting periods based on the value of the destruction of the currently vented methane.

CalBio requests that ARB to consider allowing dairy biomethane projects to renew their 10-year crediting period at least once. Currently, dairy projects are faced with the decision of choosing electricity or transportation fuels projects. Electricity projects benefit from the long-term certainty of an electricity contract. Providing at least two 10-year crediting periods will maintain the direction of many farmers to utilize their gas in California's transportation fuel market as opposed to electricity generation through the

BioMAT. It will keep the momentum underway for dairies to meet and potentially exceed, through a voluntary program, the 40% reduction of manure methane emissions.

…

Dairies make decisions for the long term and as a result having only one crediting period remains an important topic. (CALBIO1_FF67-3)

> **Agency Response:** Please refer to Response D-4.3a in Chapter IV. Further, staff notes that the 10-year crediting period is consistent with CARB's crediting period for offset projects under Cap-and-Trade, and consistent with SB 1383, which directed CARB to ensure that projects developed before the implementation of regulations to reduce methane emissions from livestock manure management operations receive credit for at least 10 years.
>
> Additionally, staff would like to clarify that the crediting period is not a limitation; rather, the crediting period is intended to provide policy certainty: applicants will be eligible for a CI that reflects avoided methane for at least 10 years. As it is currently unknown when such requirements may be implemented, in absence of the 10-year crediting period project developers and their investors or lenders would have no assurance of the number of years they could expect to receive credit for avoided methane.

D-4.2b. *Reduce Crediting Period*

Comment: Several waste-based biofuel production processes utilize material that would otherwise have decomposed and released methane, a potent greenhouse gas, into the environment. CARB has appropriately indicated that the GHG value of this avoided methane can be counted as a reduction in emissions from a given pathway. In some cases, particularly biogas from livestock operations, the avoided methane credit can drive net CI significantly below zero. This is an appropriate and scientifically-justified result, so long as there is reason to believe that the methane would have been emitted had the fuel production process not prevented it. This principle of "additionality" ensures that fuels do not receive financial value - through LCFS credits - for emissions benefits that would have happened with or without the LCFS.

At present, pathways which claim an avoided methane credit are valid for a 10 year reporting period, which can be renewed under some circumstances. If a law, regulation or mandate would require the elimination of the methane emissions which provided opportunity for the avoided methane credit, the project can still claim the avoided methane credit for the duration of the current reporting period, which could be up to 10 years. This violates the principle of additionality which underpins the life cycle analyses upon which the LCFS is based.

We suggest the following amendments to § 95488.9 (f) (3) (B)

(B) Notwithstanding (A) above, in the event that any law, regulation, or legally binding mandate requiring either greenhouse gas emission reductions from manure methane emissions from livestock and dairy projects or diversion of organic material from landfill disposal, comes into effect in California during a project's crediting period, then the project is only eligible to continue to receive LCFS credits for those greenhouse gas emission reductions for the lesser of: five years from when the law, regulation or mandate would have required the control of the methane emissions or the remainder of the project's current crediting period. The project may not request any subsequent crediting periods.

Rationale:

The provision, as currently written allows credits to be issued contrary to principles of additionality for an arbitrarily long period of time. It also provides a disincentive for early control of methane emissions, since delaying the certification of a LCFS pathway extends the time period under which the avoided methane credit can be claimed. Shortening the grace period under which non-additional credits are grated strikes a balance between ensuring that biofuel projects which control methane still receive significant LCFS support and adhering to sound science. A shorter period also restores some of the value project developers would receive for controlling methane emissions before they would otherwise be legally obligated to. By limiting the additionality grace period after control would have otherwise been required, it is more likely that early control of methane will yield more total LCFS credits than would delaying development and pathway certification until the last possible opportunity in order to ensure 10 years of avoided methane credit. (NEXTGEN3_FF65-11)

Agency Response: With this provision, staff is seeking balance between the need for regulatory additionality and policy certainty by granting a fixed number of years of crediting at the initial baseline regulatory conditions.

Further, as stated in Response D-4.2a. in this chapter, staff notes that SB 1383 directed CARB to ensure that projects developed before the implementation of regulations to reduce methane emissions from livestock manure management operations receive credit for at least 10 years.

D-4.2c. *Crediting Period for Avoided Methane is Inconsistent with eOGV Crediting*

Comment: The 15-day Modifications propose to limit credits for avoided methane emissions from dairy and swine manure projects in the event that any law or regulation requiring GHG reductions from these sources comes into effect in California during a project's crediting period (three 10-year crediting periods are being proposed). Applying this restriction appears inconsistent with allowing credits for eOGVs, which are also being implemented as a result of regulatory action. We encourage ARB to be consistent in its treatment of all fuels in the LCFS program and remove this limitation. (WSPA5_FF19-9)

Agency Response: Staff did not accept the stakeholder's suggestion to remove the crediting period for avoided methane emissions, as we believe the two provisions are consistent.

The At-Berth Regulation[59] to which the commenter refers regulates oxides of nitrogen (NOx) and particulate matter (PM), but does not regulate GHG emissions. LCFS credits are generated for reduction of GHG emissions. Furthermore, the use of shore power is only one means of compliance with the At-Berth Regulation; it is not mandated by the Regulation.

In contrast, regulations pursuant to SB 1383 are expected to require methane emission reductions at livestock manure management operations. Hence, under the net emissions quantification framework used under both the LCFS and the Compliance Offset Protocol for Livestock Projects, only reductions that are additional to regulatory requirements may receive credit.

Please also refer to Response D-4.3a in Chapter IV and Response D-4.2a in this chapter.

D-4.2d. Multiple Comments: ***Crediting Period under LCFS and Cap-and-Trade Compliance Offset Protocol***

Comment: 1. *Reporting Period Alignment:* The Compliance Offset Protocol for Livestock Projects released by CARB in November 2014 says that a crediting period is made up of ten reporting periods, beginning with the first submitted offset project data report.[1] The protocol allows for the first reporting period to be anywhere from six to twenty four months in length, with each subsequent reporting period required to be twelve months in length.[2] Language in 95488.9(f)(3)(A) of the LCFS amendments stipulates that dairy biomethane projects are eligible for three consecutive 10 year crediting periods. A number of dairy biomethane projects have participated in CARB offset programs in the past and have begun their carbon crediting period under offset protocol guidelines. These projects have first reporting periods that vary widely in length, and the initial reporting period length results in crediting periods that are shorter or longer than the ten year crediting period outlined in the LCFS program. <u>DTEBE would like clarification to ensure that projects that have already begun a crediting period under a CARB Compliance Offset program will be able to finish this current crediting period at their current schedule, rather than having the length of their current crediting period altered by the new LCFS rulemaking.</u> Projects that have begun their crediting period should be bound by this timeline regardless of whether it is longer or shorter than the ten-year crediting period for the LCFS program. CARB may mandate that subsequent crediting periods should align with the ten year LCFS crediting period outlined in this current rulemaking.

[1] See 3.6(a) of the Compliance Offset Protocol for Livestock Projects adopted November 2014

[59] For more information on the At-Berth regulation see: https://www.arb.ca.gov/ports/shorepower/shorepower.htm

[2] See 5(c) of the Compliance Offset Protocol for Livestock Projects adopted November 2014
(DTEBE2_FF20-1)

Comment: Will LCFS registrants get three 10-year periods from the time of registration, or will they would get less because of time served under Cap and Trade?

…

Recommended Action:

1. Provide greater clarity in the regulations on the compliance requirements under cap and trade for projects claiming avoided methane credits under LCFS. (ECOENGINEERS2_FF21-5d, BLUESOURCE1_FF70-6e)

Comment: Projects in the cap and trade program are verified annually for the previous year and credits are issued subsequently. How does this match up against a quarterly LCFS reporting schedule? (ECOENGINEERS2_FF21-5b, BLUESOURCE1_FF70-6c)

Agency Response: Staff agrees with comment DTEBE2_FF20-1 that projects that have already begun a crediting period as an offset project under the Cap-and-Trade Program will complete their current crediting period at their current schedule, rather than having the length of their current crediting period altered by the LCFS regulation. Because the first reporting period under the Cap-and-Trade Program may vary from six to 24 months, it does not precisely align with the 10-year crediting period in the LCFS regulation; however, the LCFS will recognize the crediting period expiration date that was determined under the offset protocol for existing projects.

As stated in the June 20, 2018 notice of changes, the crediting period begins with the first reporting to either the LCFS or Cap-and-Trade Program. If the initial crediting period expires before the regulatory requirements are in effect, projects may apply for up to two additional 10-year crediting periods. Projects that have already initiated a crediting period under the Cap-and-Trade Regulation's Livestock Projects Compliance Offset Protocol may begin credit generation under the LCFS, however, this does not initiate a new crediting period.

In response to ECOENGINEERS2_FF21-5d and BLUESOURCE1_FF70-6e, for projects that switch from crediting under Cap-and-Trade to LCFS, the crediting period under Cap-and-Trade continues under the LCFS.

Please see the response to comment ECOENGINEERS1_B5-16 in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

D-4.2e. Multiple Comments: ***Dairy Exclusion from Cap-and-Trade Regulation Compliance***

Comment: 2. *Regulatory Compliance Exemption:* One of the key questions project developers had in assessing the possibility of moving existing dairy biomethane projects from the Carbon Offset program to the LCFS program was whether these projects would continue to face the same regulatory compliance requirements in Chapter 3.7 of the Compliance Offset Protocol for Livestock Projects. The "Draft Dairy Crediting Guidance" released by CARB in December 2017 noted that Chapter 3.7 requirements were not applicable to projects that participate in the LCFS program. DTEBE asks that CARB explore a way to put this regulatory compliance exclusion into the LCFS rules to provide long-term clarity for dairy biomethane producers. Doing so would give producers confidence that similar problems faced by projects in the Cap-and-Trade program will not be replicated in the LCFS program. (DTEBE2_FF20-2)

Comment: AECA continues to recommend specific language be included in the amendments to clarify regulatory compliance requirements. Specifically clarifying that LCFS Requirements do not include regulatory compliance requirements (or by an appropriate reference to the Manure Management Operations Crediting Document) is an important consideration for informing project risk and capital sources. (AECA3_FF35-2)

Comment: In the December 2017 draft guidance document mentioned above, ARB staff provided a table of specific requirements from the ARB Livestock Compliance Protocol which will be excluded from the projects seeking credits under the LCFS program. CalBio requests this table be added to the LCFS regulation to memorialize this guidance in the formal regulation. This is to ensure there is clarity around ARB's position about which aspects of the ARB Livestock Compliance Protocol are exempted for LCFS purposes for dairy biomethane projects, particularly as it relates to regulatory compliance. Developers and financial parties need certainty that projects will remain exempt from this requirement and be treated consistently with all other project types under the LCFS program. (CALBIO1_FF67-5)

Agency Response: Please refer to Response D-4.3b in Chapter IV.

D-4.2f. Multiple Comments: *Overlaps with Cap-and-Trade Compliance Offset Protocol*

Comment: 3. *Simultaneous Participation in LCFS and Compliance Offset Credit Programs*: Based on current program guidelines, projects are barred from participating in both the Compliance Offset Credit program and the LCFS program in the same carbon reporting year. Many dairy biomethane projects are operating under long-term electric contracts that generate compliance offsets. Some of these projects are generating additional biomethane that cannot be used in their current engine systems – biomethane which could be utilized for other purposed such as transportation. DTEBE asks that CARB provide amended language to allow for a single project to generate both Compliance Offset Credits and LCFS Credits in a single carbon reporting year. Allowing participation in both the LCFS and Compliance Offset programs would allow producers to direct excess biomethane to the vehicle fuel market - ensuring all available methane is directed to beneficial uses and projects achieve the maximum amount of

carbon reduction possible. This will encourage further development of dairy biomethane projects and encourage the use of more negative carbon fuel in California. (DTEBE2_FF20-3)

Comment: In December 2017, ARB staff posted Draft Guidance on the Impact of Adopting Regulations Pursuant to SB 1383 on the Ability to Continue to Generate Credits Under the Low Carbon Fuel Standard and Cap-and-Trade Program for the Reduction of Methane Emissions from Manure Management Operations. In this document, ARB staff states that "projects receiving credit under the LCFS many not receive credits under the Cap-and-Trade Program and the Livestock Protocol within the same reporting period, even for reductions that are not credited under the LCFS program." It is unclear why this provision exists. A number of our dairy biomethane projects operating under long-term electric contracts and are generating additional biomethane that could be used as transportation fuel instead of vented or flared (or in some cases diverted). CalBio requests that this language be amended to allow for a single project to generate both Compliance Offset Credits and LCFS Credits in a reporting period provided the ARB approved verifier is able to confirm the proportion of avoided methane that can be attributed to the CCO pathway compared to the LCFS pathway. This will eliminate any potential for double counting. Allowing for this will increase flexibility for the project and enable existing electricity projects to smoothly transition reporting from one program to another without the loss of credits. (CALBIO1_FF67-2)

Agency Response: Please refer to Response D-4.3c in Chapter IV.

D-4.2g. Comment: However, it is unclear whether a project needs to be registered in the CA Cap and Trade program and be fully compliant with all its requirements in order to claim avoided methane emission credits. This lack of clarity results in the following uncertainties for projects:

- If the dairy has a spill event or other compliance issues under cap and trade, will it impact the LCFS carbon intensity score? (ECOENGINEERS2_FF21-5e, BLUESOURCE1_FF70-6b)

  Agency Response: Please refer to Response D-4.3d in Chapter IV for the response related to the spill event, and refer to the response to comment ECOENGINEERS1_B5-15 in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations, for the response related to whether a project needs to be registered in the Cap-and-Trade program. In short, the project does not need to be registered in the Cap-and-Trade Program.

D-4.3. *Renewable Natural Gas Sources from Outside California*

Comment: To that point, RNG from dairy and swine manure projects may come from jurisdictions outside California due to the use of indirect accounting. WSPA suggests that both in-state and out-of-state projects receive credit for avoided methane emissions

once SB 1383 is fully implemented to maintain the global GHG reduction benefits provided by those out-of-state projects. (WSPA5_FF19-10)

Agency Response: The LCFS does not discriminate between in-state and out-of-state fuel producers based on their geographic location. The proposed changes in this rule continue to encourage RNG projects both inside and outside of the state. Once the methane reduction requirements of SB 1383 are implemented, both in-state and out-of-state producers will continue to be evaluated equivalently: new applications will only be eligible for avoided methane that is above and beyond any reduction required by California law or regulation, and existing projects will be evaluated under the baseline regulatory conditions that were in place at the time the crediting period was initiated until the end of their crediting period.

D-4.4. *Specified Source Feedstocks*

D-4.4a. Comment: Page 55: Page III-94 of the Staff Report designated waste-derived fuels and pipeline-injected biomethane from landfills as "specified source feedstocks" to help provide transparency of the feedstock chain for high-risk feedstocks which would be subject to additional documentation requirements. The Task Force requests that CARB incorporate language into Section 95488.8(g)(1)(A) of the Health and Safety Code to ensure that the additional documentation requirements are not overly burdensome, compared to documentation requirements for other feedstocks to the point of discouraging the production of waste-derived fuels and pipeline-injected biomethane from landfills. (TASKFORCE2_FF7-6)

Agency Response: Please refer to Response E-4.2 in Chapter IV.

D-4.4b. Comment: Page 95: Page III-137 of the Staff Report designated separated food waste as a "specified source feedstock" subject to additional documentation requirements. The Task Force requests that CARB incorporate language into Section 95491.1(a)(2)(F) of the Health and Safety Code to ensure that this additional documentation is consistent with Senate Bill 1383 implementing regulations such that it does not discourage use of separated food waste as a feedstock to produce fuel. (TASKFORCE2_FF7-7)

Agency Response: Please refer to Response E-4.3 in Chapter IV.

D-4.5. *Organic Waste Diversion*

D-4.5a. Comment: The Staff Report stated that CARB anticipates that Renewable Natural Gas (RNG) pathways will continue to have carbon intensities (CIs) below the declining benchmarks set forth by these regulations and therefore RNG will maintain its opt-in status. The Task Force would like to know if the calculation for Low Carbon Fuel Standard (LCFS) credits for waste-derived RNG takes into consideration the amount of greenhouse gas (GHG) emissions that will be reduced by diverting waste away from landfills, and would like to be provided with a copy of analysis. (TASKFORCE2_FF7-1)

Agency Response: Please refer to Response D-4.4a in Chapter IV.

D-4.5b. Comment: This Comment requests that clarifying language be inserted into a new subsection pertaining to "Carbon Intensities that Reflect Avoided Methane Emissions". The specific provision referenced is 17 CCR §95488.9(f).

As further discussed below, Fulcrum has received a very low carbon intensity ("CI") score for the transportation fuel that it will produce. Fulcrum is requesting this clarification in the regulation because avoided methane emissions from landfill-diverted organics are an important component of Fulcrum's very low CI score.

…

The proposed subsection addresses two distinct categories of avoided methane emissions: 1) dairy and swine manure, and 2) organic material diverted from landfill disposal. Both of these categories are specifically referenced in the subsection's heading entitled, *"Carbon Intensities that Reflect Avoided Methane Emissions from Dairy and Swine Manure or Organic Waste Diverted from Landfill Disposal."* Within the subsection, §95488.9(f)(1) provides specific requirements that apply to dairy and swine manure; and §95488.9(f)(2) provides specific requirements that apply to organics diverted from a landfill.

The final provision, §95488.9(f)(3) only references the dairy and swine manure category in its heading, "Carbon intensities that reflect avoided methane emissions from dairy and swine manure projects are subject to the following requirements for credit generation:" However, §95488.9(f)(3)(A) and §95488.9(f)(3)(B) specifically refer to "landfill-diversion pathways" and "diversion of organic materials from landfill disposal" respectively. Subsection §95488.9(f)(3) is of importance because it establishes crediting periods for projects that have received Executive Officer approval.

The intent language coupled with the language of §95488.9(f)(3)(A) and §95488.9(f)(3)(B) clearly establish that the subsection encompasses methane reductions from organics diverted from a landfill. Therefore, it is recommended that the heading of §95488.9(f)(3) be revised as follows: "Carbon intensities that reflect avoided methane emissions from dairy and swine manure projects <u>and landfill-diversion projects</u> are subject to the following requirements for credit generation:" (recommended additional language indicated by underline). This recommended language is intended to remove any ambiguity from the subsection. (FULCRUM2_FF24-1)

Agency Response: In response to this comment, staff has modified section 95488.9(f)(3) to clarify that organic waste projects are intended to be included in this provision.

D-4.6. *Indirect Book-and-Claim Accounting*

D-4.6a. Multiple Comments: *Suggestion to Exempt Physical Storage from the Proposed Limit for Indirect Book-and-Claim Accounting of Renewable Natural Gas*

Comment: We have also asked staff for an exception for this limitation in the case of physical storage. In our previous comments, RNG Coalition expressed concerns that a project will have stored a significant amount of gas during the data collection period, and the full volume of this gas may not be able to be discharged in this time frame. Therefore, we respectfully ask that you consider explicitly excluding physical storage from the three-calendar-quarter limitation on book-and-claim accounting for RNG. (RNGC3_FF46-5b)

Comment: However, the proposed provisions for book-and-claim accounting, specifically with respect to biomethane, still do not provide adequate clarification for biomethane injected into physical storage.

Clean Energy believes that the book-and-claim limitation on environmental attribute recognition must not apply to biomethane injected into physical storage. All biomethane projects are subject to lengthy project registration periods, especially at the federal EPA level with RFS and quality assurance plan (QAP) approval, which jeopardizes the starting of cash flow necessary for recouping up front capital investments.

Furthermore, the LCFS regulation requires a minimum of three months of project operation before obtaining a provisional CI, potentially leaving only two subsequent quarters for provisional pathway approval under this book-and-claim timeframe limitation. Project developers cannot afford to lose any environmental value associated with produced biomethane, especially in the vulnerable start-up phase. Extending the book-and-claim limitation to three quarters provides zero assurances against lost environmental value for a producer who is subject to regulatory approval processes that have been proven to take over a year in some cases. To mitigate this regulatory risk and protect their environmental value, the RFS allows biomethane developers to secure storage agreements to deliver initial production of biomethane to physical storage while project and pathway registrations are pending. Delivering initial biomethane to storage ensures that the biomethane producer can recognize the full environmental benefit of the biomethane as a transportation fuel when the necessary registrations are final. This is acceptable under the RFS and therefore should be acceptable under the LCFS as well.

Clean Energy requests that staff add clarifying language to Section 95488.8(i)(2)(A) to exempt any biomethane delivered to physical storage from the limited three-quarter timeframe for recognition of environmental benefit. This will ensure that biomethane producers will not unnecessarily lose value, will reduce unintentional financial risk to the biomethane project, and will keep the LCFS regulation aligned with the RFS in terms of recognition of environmental attributes. (CE4_FF52-3)

Comment: The extension of three calendar quarters for the timeframe of when RNG can be injected into the pipeline in North America, and the time that quantity is sold is something that underlines the flexibility of the LCFS and allows it to be altered to the fuel market current conditions. But the staff may want to consider exempting the limitation of physical storage. The collection period is not one that is sufficient enough to discharge all of the RNG. It is important for flexibility, and practicality to be considered with this provision. The LCFS should not discourage the storage of fuel by setting storage limits that are not feasible for the industry. (CNGVC3_FF59-4)

> **Agency Response:** Staff would like to clarify that the three-quarter clock begins upon the injection of Renewable Natural Gas (RNG) into the common carrier pipeline. The RNG can be stored before the injection into pipeline indefinitely, but once injected in the pipeline subsequent storage of RNG in a physical storage would not reset the three-quarter clock. This is consistent with the three-quarter limit for book-and-claim accounting for renewable electricity and the three-quarter transfer period provided to liquid fuel providers to pass on the credit or deficit generator status.

D-4.6b. Multiple Comments: ***Suggestion for the Implementation of the Proposed Limit for Indirect Book-and-Claim Accounting of Renewable Natural Gas***

Comment: However, this system still forces producers to bear the risk of any unexpected delays that a new project may have in registering a provisional CI score. <u>DTEBE suggests that for newly registered projects, the three calendar quarter clock for environmental attribute generation begins once a provisional CI is approved by CARB.</u> Allowing new projects to have three calendar quarters after a provisional CI score is approved will allow producers to receive the full value for their project CI, even if there are unexpected delays in registering for the LCFS program. (DTEBE2_FF20-5)

Comment: We would like to suggest that this date begins once the provisional CI is achieved. This removes uncertainty based on ARB's own workload. (CALBIO1_FF67-1b)

> **Agency Response:** Staff proposed the three-quarter limit for book-and-claim accounting of Renewable Natural Gas (RNG) to ensure the environmental attribute associated with RNG is claimed in the program within that limit. The three-quarter clock begins upon the injection of RNG into the common carrier pipeline and provides a consistent reference in time. This is consistent with the three-quarter limit for book-and-claim accounting for renewable electricity and the three-quarter transfer period provided to liquid fuel providers to pass on the credit or deficit generator status. Relying on the date of receipt of the provisional CI would not be ideal to start the three-quarter clock as it depends on numerous factors and may not provide a consistent time reference. Moreover, staff is confident that if the fuel pathway applicant can successfully provide all the necessary information then the certification should be completed within the permissible three-quarter limit providing the applicant to match the environmental attribute for reporting in LCFS.

D-5. *Hydrogen*

No comments were received on this topic during the 1st 15-day comment period.

D-6. *Electricity*

D-6.1. *Support for the Proposed Modifications to the Electricity Provisions*

D-6.1a. Multiple Comments: *Support for the Modifications to the Electricity Provisions*

Comment: eMotorWerks supports the California Air Resources Board (ARB) staff's initiative and foresight in developing proposed LCFS amendment language that would encourage the expanded use of low carbon resources in electrifying the state's transportation networks. (EMW1_FF45-1)

Comment: CalETC supports the remaining 15-day modifications pertaining to electricity fuel in the LCFS. We believe CARB staff has continued to improve implementation of the LCFS and better calculate the benefits of electricity as a transportation fuel. (CALETC3_FF60-12)

Comment: The Smart EV Charging Group continues to support the California Air Resources Board (ARB) staff's initiative and foresight in developing proposed LCFS amendment language that would encourage the expanded use of low carbon resources in electrifying the state's transportation networks. (SEVCG3_FF61-1)

Comment: The Smart EV Charging Group supports the ARB's efforts to facilitate and incentivize greater EV usage and charging through the LCFS program. (SEVCG3_FF61-8)

> **Agency Response:** Staff appreciates the commenters' support for the amendments to electricity provisions.

D-6.1b. *Support for Addition of New Electricity Applications*

Comment: The Port believes the proposed amendments will significantly expand the LCFS program to allow for more mobile freight and cargo-handling equipment to qualify for credit generation. This provision is helpful and will likely spur the interest of the industry to participate in the LCFS program. In furtherance of this goal, the Port offers the additional recommendations described below to increase LCFS credit uptake by the industry and thus promote further investment in zero emissions technologies. (POLB1_FF6-1)

> **Agency Response:** Staff appreciates the commenters' support for the addition of new electricity applications, and responds to the specific recommendations elsewhere.

D-6.1c. *Support LCFS for Promoting ZEV Adoption and Transportation Electrification in California*

Comment: eMotorWerks appreciates the hard work of CARB Staff and the Board in advancing the LCFS regulation, particularly the provisions related to zero emission vehicles. (EMW1_FF45-8)

> **Agency Response:** Please see Response D-6.1j, Support LCFS for Promoting ZEV Adoption and Transportation Electrification in California, in Chapter IV.

D-6.1d. Multiple Comments: *Support Electric Distribution Utilities (EDU) as Base Credit Generator for Residential EV Charging*

Comment: CalETC supports the current program design with utilities generating "base" LCFS credits for residential charging and returning the value of those credits to electric vehicle drivers. CalETC and the utilities are committed to continue working with stakeholders and regulators to improve the programs supported by utilities LCFS credit revenue. We share the commitment to accelerate the market for electric vehicles and support the Administration and Legislature in meeting the state's transportation electrification goals. The utilities are uniquely positioned to work with administration and legislature to invest the LCFS credit value, they are either local public entities, as is the case with publicly-owned utilities, or they are economically regulated, as it is the case with investor-owned utilities. (CALETC3_FF60-2)

Comment: 1. CalETC supports the 15-day modification language that clarifies that the allocation of base residential charging LCFS credits may only go to electric distribution utilities (EDUs) and that other parties may not claim these credits or use the reporting tool for CA statewide average electricity carbon intensity (CI).[13]

[13] In the 15-day modifications, see section 95491(d)(3)(A)6. (Fuel Transactions and Compliance Reporting) on page 92 and section 95483 (c)(1) and (c)(2) (Fuel Reporting Entities) on pages 10 and 11.

(CALETC3_FF60-13)

Comment: PG&E continues to support the electrical distribution utility (EDU) as the credit generator for the base credits from residential EV charging. (PGE2_FF64-4a)

Comment: a. issue residential base credits on a quarterly basis; and

…

I. Issue residential base credits on a quarterly basis

We support CARB staff's proposal to issue residential base credits on a quarterly basis rather than an annual basis.[12] This would provide utilities with more liquidity and them to replenish program funding more quickly, which should result in more benefits to consumers.

[12] § 95491(d)(3)(A)(1).

(TESLA2_FF69-10)

Agency Response: Please see Response D-6.1j in Chapter IV.

In further response to CALETC3_FF60-13, staff would like to clarify that opt-in EDUs are the only eligible entities to generate base credits for residential EV charging using California average grid electricity CI but other entities are eligible to report California average grid electricity for non-residential EV charging and other transportation applications.

D-6.1e. *Support for Proposed Quarterly Reporting of Daily Average EV Charging Rate for Calculation of Base Credits*

Comment: 5. CalETC supports the 15-day modifications that result in EDUs receiving LCFS credit allocations for base residential charging credits quarterly instead of yearly.[18]

[18] See section 95491(d)(3)(A)(1) in the 15-day modifications

(CALETC3_FF60-17)

Agency Response: Staff appreciates the commenter's support to proposed quarterly crediting of the base credits for non-metered residential EV charging. Staff believes this would allow the utilities to monetize credits sooner to fund the proposed statewide rebate program.

D-6.1f. Multiple Comments: *Support for the Incremental Credit Provisions*

Comment: In general, BMW supports CARB's incremental LCFS credit program. The concept of providing additional LCFS credits for the use of renewable energy in charging electric vehicles should be added to the LCFS program and can provide an incentive for drivers, OEMs, utilities and facilities to reduce emissions associated with electric vehicle charging. (BMW1_FF66-1)

Comment: We support staff's proposal to permit additional credit generation based on the matching of recorded EV charging with renewable solar energy generation (0 CI electricity) and smart charging when there is an excess of renewable electricity on the grid for both residential and non-residential EV charging. These proposals are aligned with California's broader renewable energy goals and will help spur near-term EV adoption. (TESLA2_FF69-14)

Agency Response: Please see Response D-6.1g, Support for the Incremental Credit Provisions, in Chapter IV.

D-6.1g. *Proposed Reporting for Incremental Credits for Residential EV Charging*

Comment: 3. Assuming the LCFS regulation returns the reporting exemption for EDUs on base and incremental residential charging credits,[15] CalETC supports the 15-day modification language that would allow EDUs to generate incremental residential credits for non-metered electricity linked to customers with green tariffs if no other party is claiming these credits.[16]

[15] See comment 3 above.

[16] See section 95486.1 (c)(2)(A)(1), section 95491(d)(3)(A) and section 95481 (a).
(CALETC3_FF60-15)

Agency Response: Staff appreciates the commenter's support for allowing load-serving entities, including opt-in utilities, to generate incremental credit for non-metered residential EV charging if no other entity is claiming it. Staff proposed the incremental credit generator for non-metered residential EV charging must be able to provide, upon request of the Executive Officer, the VIN for each EV being charged and evidence of EV vehicle registration and low-CI electricity supply at the same location.

D-6.1h. *Support for the Proposed Fueling Supply Equipment Registration Requirements*

Comment: 6. CalETC supports the 15-day modification[19] that makes reporting optional for EDUs that are reporting metered electricity to generate base residential charging credits.

[19] Section 95483.2 (b)(8)(B)(4) on page 15 in the 15 day modifications
(CALETC3_FF60-18)

Agency Response: Staff appreciates the commenter's support for the proposed FSE registration requirements for reporting metered electricity to generate base credits for residential EV charging.

D-6.1i. Multiple Comments: *Support for the Proposed Addition of New Transportation Applications*

Comment: *1. Inclusion of Shore Power should be written into the Rule, even if use of this power is required by regulation.* Use of shore power instead of marine diesel for ocean-going vessels (OGV) berthed at port has the proven benefit of achieving significant reductions in greenhouse gases, as well as co-pollutants. OGVs are responsible for up to 50% of the Port's greenhouse gas emissions and the use of shore power for all vessels at the Port could dramatically lower this number. Crediting shore power would encourage ongoing investment in electrical infrastructure such as new power outlets where necessary, to ensure 100% compliance with the regulation, and would incentivize vessel operators to go beyond the regulation, particularly if the Port uses LCFS-generated revenues to increase existing Port incentive programs. The ownership of credits for shore power is discussed below. (POLB1_FF6-2)

Comment: LADWP supports the addition of electric cargo handling equipment (eCHE) and electric auxiliary engines for ocean-going vessels (eOGV) as new electric transportation applications. The addition of these new vehicle applications will further incentivize ongoing efforts taken by LADWP to improve air quality in its service territory. In June 2018, the Board of Water and Power Commissioners approved a memorandum of understanding between LADWP and the Los Angeles Harbor Department (LAHD) to fund electrification projects at the Port of Los Angeles. By providing funding to the LAHD, LADWP is contributing to the goals of the San Pedro Bay Ports Clean Air Action Plan, which is aligned with ARB's Sustainable Freight Action Plan. The anticipated

benefits include reduced amounts of GHG, particulate and nitrogen oxide emissions for improved air quality, and reduced health risk for the residents. (LADWP2_FF10-5)

Comment: PMSA supports the inclusion of eTRU, eCHE, and eOGV as opt-in categories eligible for credit generation under the LCFS regulation. The maritime industry is expanding its use of electrically-powered equipment in some cases. The inclusion of these equipment categories will create incentives for terminal and vessel operators to expand their use of electrified equipment, but only if they are the beneficiaries of the credit generation. (PMSA1_FF14-1)

Comment: The opportunity to opt-in for credit generating opportunities in these categories will create meaningful incentives for ocean carriers and terminals to use low carbon-intensive options that will reduce greenhouse gases. In addition, by creating opt-in credit generating opportunities, CARB will also support its existing regulatory programs that seek to reduce criteria and toxic pollutants from these source categories. (PMSA1_FF14-4)

Comment: CleanFuture supports the proposed inclusion of electric transport refrigeration units (eTRU) in the proposed amendments. Inclusion of eTRU in the LCFS will help incentivize and accelerate the transition of transport refrigeration toward the use of clean electricity instead of diesel to deliver our fresh, perishable, and frozen foods. The LCFS and other actions by CARB to incentivize electrified TRUs are necessary to help transform the market.[1]

[1] Community Air Protection Funds Supplement to the Carl Moyer Memorial Air Quality Standards Attainment Program 2017 Guidelines https://www.arb.ca.gov/msprog/cap/docs/cmp proposed cap supplement 20180312.pdf

(CF1_FF47-2)

Comment: 2. CalETC supports the 15-day modification language that clarifies that ships plugged in at berth and electric cargo handling equipment may now earn LCFS credits.[14]

[14] See section 95483(c) (5), section 95483.2(b)(8), section 95481 (a),and section 95486.1(a) in the 15-day modifications

(CALETC3_FF60-14)

> **Agency Response:** Staff appreciates the commenters' support for the proposed new electric transportation applications eligible for crediting in LCFS, including Electric Transport Refrigeration Unit (eTRU), Electric Cargo Handling Equipment (eCHE), and Electric shore power for Ocean-going Vessel at-berth (eOGV). Staff believes the proposed modifications would further promote the use of electricity as low carbon transportation fuel resulting in additional GHG emission reductions.

D-6.1j. Multiple Comments: *Support for the Proposed EER-Adjusted CI Tier 2 Pathway*

Comment: Lyft Supports Tier 2 Application Process For EER-adjusted CIs

In addition, Lyft would like to express its strong support for the new proposed Section 95488.7(a)(3), providing a Tier 2 application process for requesting Energy Economy Ratio-adjusted (EER-adjusted) carbon intensities (CIs) for alternative fuels used in transportation applications not included in existing Table 5. This forward-looking provision will enhance the efficacy and dexterity of the LCFS program by ensuring new technologies and transportation applications properly are recognized and incentivized. We note proposed Section 95488.7(a)(3) would require the methodology used for calculating an EER-adjusted CI to compare useful output from the alternative fuel technology to that of a comparable conventional fuel technology. To ensure this innovative provision is maximally effective, the regulation should provide more clarity regarding what constitutes a "comparable conventional fuel technology." By their very nature, "innovative technologies and transportation applications" likely are to include outside-the-box approaches that are not directly analogous to any commonly used conventional mode of transit. Accordingly, this provision should clarify the meaning of "comparable conventional fuel technology," or perhaps specify an alternative approach to be used when there is no widely adopted equivalent conventional application. For example, the useful output of an alternative fuel technology instead might be compared to that of the conventional technology it is most likely to replace. This approach would help to ensure EER-adjusted CIs accurately reflect carbon emissions reductions. Lyft commends ARB for crafting regulations that not only accommodate but actively spur the development and deployment of clean transit technologies. (LYFT1_FF50-2)

Comment: Additionally, the opportunity to submit Tier 2 applications to request EER-adjusted CI values for vehicle-fuel combinations not previously considered is a welcomed addition. (SREC2_FF53-2)

Comment: 5. CalETC supports the 15-day modification allowing other types of electric vessels and non-road equipment that do not earn credits today (due to lack of an EER) to be able to earn credits under the revised LCFS through a Tier 2 application process. CalETC also continues to request that the LCFS be amended to create a default, conservative EER for electric marine vessels and non-road equipment.

…

5. CalETC supports the 15-day modification allowing other types of electric vessels and non-road equipment that do not earn credits today (due to lack of an EER) to be able to earn credits under the revised LCFS through a Tier 2 application process. CalETC also continues requests that the LCFS be amended to create a default, conservative EER for electric marine vessels and non-road equipment.

CalETC encourages CARB staff to develop an EER[8] for the marine, airport, mining, agricultural and material handling industries, these industries could benefit from this provision and further the state's energy diversity and LCFS goals. CalETC also continues to recommend CARB staff create a temporary, default, conservative EER for electric vessels and non-road equipment. A conservative, default EER would allow for broader engagement in the LCFS program. A temporary, default EER would not

impede efforts to engage in the Tier 2 application process and the Tier 2 EERs would improve upon the temporary default EER in future years.

[8] See Section 95483(c)(7), section 95486.1(a)(2), section 95488.7(a)(3) and section 95491(d)(3)(I)

(CALETC3_FF60-10)

Agency Response: Staff appreciates the commenters' support for the proposed Tier 2 pathway process for obtaining an EER-adjusted CI value for a vehicle-fuel combination that is not included in the Table 5. Currently, in the LCFS the reporting and credit generation for a vehicle-fuel combination is only possible if there is an EER value provided in the Table 5. In addition, new EERs can only be added through a rulemaking process that limit program's ability to timely recognize and incentivize new and innovative technologies using low-carbon fuels.

In further response to CALETC3_FF60-10, staff would like to note that as EER values are critical for credit and deficit calculations they must be based on engineering data and staff strives to develop EER values based on best available data. Therefore, staff did not propose to create default EER that may not be representative of the actual energy economy of the vehicle-fuel combination.

D-6.1k. Multiple Comments: ***Support for the Pathways Available for Reporting Non-EV Charging Applications Using Electricity as Transportation Fuel***

Comment: III. Indirect Accounting of Renewable Electricity for EV Charging Requires Clarification In Order to Be Utilized by Fuel Reporting Entities.

eMotorWerks supports the proposed amendment to §95488.8.(i)(A) to increase the number of quarters for which renewable electricity attributes may be applied for purposes of the LCFS program. Given the administrative latency of renewable attribute market systems, this increase in time should reduce the likelihood of infeasible utilization of this provision.

§95488.8.(i)(B)(1) may still create barriers for fuel reporting entities to utilize this provision to generate LCFS credits from low CI electricity – both for residential and non-residential EV charging.

eMotorWerks proposes that a fuel reporting entity utilizing a low CI pathway can submit and confirm fuel transactions from EV charging within 90 days of quarter end, but confirm the retirement of renewable attributes no later than 210 days after the end of the reporting quarter. This will ensure renewable energy attributes generated within a single quarter are still utilized within three quarters for the purpose of LCFS credit generation.

Non-LSE fuel reporting entities will need to contract with third-party electricity and renewable attribute market participants to execute on the low CI electricity requirements of the LCFS regulation for EV charging. In addition, fuel reporting entities may own renewable electricity equipment and/or designate a fuel reporting entity to utilize the

renewable attributes for LCFS credit generation. As such, §95488.8.(i)(B)(1) should be clarified:

1. Electricity is generated using equipment owned by, or under contract to the pathway applicant or its contracted agent for all environmental attributes of the claimed electricity. In order to substantiate renewable electricity claims, the applicant must make contracts or ownership information available to the Executive Officer, upon request, to demonstrate that the electricity meets the requirements of this subarticle. ~~Generation i~~Invoices or reports (if equipment owned) are required to substantiate the quantity of renewable electricity produced from the renewable assets. Monthly invoices or reports must beunredacted copies of originals showing electricity sourced (in kWh) and contracted price (if applicable); (EMW1_FF45-5)

Comment: III. The Smart EV Charging Group Proposes that Electricity and corresponding RECs be Utilized Within Three Quarters for LCFS Purposes.

The Smart EV Charging Group supports the proposed amendment to § 95488.8.(i)(A) to increase the number of quarters for which renewable electricity attributes may be applied for purposes of the LCFS program. Given the administrative latency of renewable attribute market systems, this increase in time should reduce the likelihood of infeasible utilization of this provision.

However, the implications of § 95488.8.(i)(B)(1) may still create a timing mismatch between LCFS credit generation and renewable electricity attributes available for retirement due latency between electricity generation and attribute availability. The Smart EV Charging Group suggests staff provide clarifying language to confirm that a reporting entity utilizing a low CI pathway can submit and confirm fuel transactions under the current quarterly schedules but provide confirmation of renewable attribute retirement subsequent to the 90-day deadline following the end of the reporting quarter, so long as no later than 210 days after the end of the reporting quarter. This will ensure that electricity and renewable energy attributes generated within a single quarter are still utilized within three quarters for the LCFS purpose. (SEVCG3_FF61-4a)

Agency Response: Staff appreciates the commenters' support for proposing that the book-and-claim accounting for low-CI or renewable electricity could span up to three quarters instead of only two quarters. Staff believes this change would allow entities sufficient time to generate and retire environmental attributes associated with low-CI electricity claimed in LCFS. To provide clarity on reporting, staff also proposed that the REC retirement must be demonstrated in the quarterly report for the electricity claimed in that quarter.

In further response to (EMW1_FF45-5), staff did not adopt commenter's recommendation but proposed minor updates to the section 95488.8(i)(B)(1) to clarify the requirements for indirect book-and-claim accounting or low-CI or

renewable electricity when generated directly or supplied through contract to the entity making the claim.

D-6.2. *Zero-CI Electricity Sources*

Comment: San Francisco had requested in its initial comments that:

…

- All zero-CI, RPS-eligible resources be included in the Lookup Table Pathway to be consistent with state law; and

…

Section 94588.1(b)(2)(A) is inconsistent with California law because it does not include all Zero-CI, RPS-eligible resources

The latest proposed modifications to the LCFS regulation are inconsistent with California law in that Section 95488.1(b)(2)(A) does not include all RPS-eligible, zero-CI resources. According to the 15-day notice:[2]

[2] Notice of Public Availability of Modified Text and Availability of Additional Documents and Information, issued June 20, 2018.

> In response to stakeholder comments, staff examined electricity generation pathways in GREET, and generation sources that meet eligibility for California's Renewable Portfolio Standard, to determine all sources that are expected to achieve a zero CI. Stakeholders also requested the addition of geothermal and biomass power as zero-CI sources; however, these sources are low-CI, yet typically result in some non-zero emissions. The additions provide flexibility for all zero-CI generation sources to utilize the Lookup Table pathway.[3]
>
> [3] 15-day Notice, p. 15 (emphasis added, internal citation omitted).

Unfortunately, proposed Section 95488.1(b)(2)(A) does not include all of the zero-CI resources identified in the California RPS, specifically those resources enumerated in Public Utilities Code Sections 399.12 and 399.12.5. This includes incremental improvements to hydroelectric systems, conduit hydroelectric facilities, and selected water conveyance hydroelectric units.[4] As noted in San Francisco's initial comments, and consistent with CARB's own treatment of these resources, all of these resources qualify as zero-CI.[5]

[4] Also see the California Energy Commission's Renewables Portfolio Standard Eligibility Guidebook (9th Ed.), Ch. 2.F

[5] These resources are classified as zero-CI under CARB's Mandatory Reporting Requirements (MRR) for GHG emissions (Section 95101(f)(1)) and are assigned a zero-CI under the CA-GREET model used by CARB in the LCFS program to determine GHG emissions from the electric sector.

The proposed definition of zero-CI RPS resources appears to be based on the incomplete, and hence incorrect, definition of the term "renewable electrical generation facility" in Public Resources Code Section 25741 (adjusted to exclude RPS resources staff believe have incremental GHG emissions). The full definition of what constitutes a

"renewable electrical generation resource" is contained in Public Utilities Code Sections 399.12 and 399.12.5, which expressly elaborate and build on the definition in Public Resources Code Section 25741. As the California Energy Commission's RPS Eligibility Guidebook, on which ARB staff relies,[6] states:

[6] 15-day Notice, footnote 2.

> *Eligible renewable energy resource* — consistent with the California Code of Regulations, Title 20, Section 3201 (k), means an electrical generating facility that the Energy Commission has determined meets the definition of a "renewable electrical generation facility" in section 399.12 (e) of the Public Utilities Code, including a facility satisfying the criteria of section 399.12.5 of the Public Utilities Code, and has certified as an RPS-certified facility.[7]
>
> [7] California Energy Commission's Renewables Portfolio Standard Eligibility Guidebook (9th Ed.), p. 81.

…

§ 95488.1. Fuel Pathway Classifications.

(b) *Lookup Table Classification.*

(2) *Lookup Table Pathways That Require a Fuel Pathway Application*. Fuel pathway applicants for renewable electricity and all hydrogen Lookup Table pathways must register in the AFP and meet the application requirements of section 95488.5(b). Fuel pathway applicants may then report fuel transactions in the LRT-CBTS for the fuel pathways listed in 95488.1(b)(2)(A) through (F).

(A) Electricity (100 percent zero-CI sources, which include: solar photovoltaic, wind, solar thermal, small hydroelectric facilities of 30 megawatts or less, <u>hydroelectric facilities meeting the requirements of Public Utilities Code sections 399.12 or 399.12.5,</u> ocean wave, ocean thermal, and tidal current) (CCSF3_FF51-2)

Agency Response: Please refer to Response D-6.3 in Chapter IV.

D-6.3. *Energy Economy Ratio Updates*

D-6.3a. Multiple Comments: *Proposed EER for Electric Cargo Handling Equipment (eCHE)*

Comment:

- The 15-Day Notice states the estimated average efficiency for cargo handling equipment is 38%, but this is unrealistic and unsupported by the record. Indeed, the maximum efficiency (the highest possible percentage) for diesel engines is 41-42%. (See Exhibit "C" at 2.)
- The hours of operation by equipment type for cargo handling vehicles is unclear. Table 1 of Appendix D lists the hours of operation by vehicle type, and includes "hours" ranging from 1,900 to 401,633. The Table does not state annual use

rate, and it is unclear what these values refer to. (See *id*.) (GROWTHENERGY2_FF56-18)

Comment: The derivation of EER values for cargo-handling equipment is based on a modeled relationship between engine efficiency and load factor. The average load factor for different cargo handling equipment is based on load factors used for emission inventories and from recent work for the Port of Los Angeles. The documentation states that CARB's EER calculation methods assume no losses of energy during battery charging or conversion of energy to useful work. To be consistent with prior calculation methods, staff assumed no losses for electrical non-yard truck equipment, i.e. the efficiency is 100%. Therefore, the inverse of diesel engine efficiency is used to estimate EERs for the ratio of electrical equipment to diesel equipment.

ARB utilizes a model to estimate the efficiency of a diesel engine as a function of the load factor imposed on the engine. While the modeled relationship between diesel engine efficiency and load factor is consistent with engineering principles, there is little documentation on the load factors listed by equipment type in Appendix D. Table 1 of Appendix D also lists an "hours of operation" by equipment type that is footnoted but the footnote itself is missing. It is unclear what the hours of operation refers to as it varies by equipment type from 1900 to 401,633 so it is <u>clearly not</u> the annual use rate.

The load factors span the range from 0.2 to 0.59 but the derived EER is 2.6. Since the EER is the inverse of engine efficiency, the estimated average efficiency is 1/ 2.6 or 38.5%. The peak efficiency (the highest value) for a diesel engine, which typically occurs at load factors of 0.85 to 0.9, is 41% to 42% so that an operating average efficiency so close to the maximum value seems unreasonably high. Appendix D also states that diesels operate at average efficiency between 30 and 35%, so that the EER is inconsistent with ARB's own findings.

It is unclear why the ARB assumes no losses of energy during battery charging or conversion of energy to useful work for electric equipment, as these losses are about 20 to 25% of total energy use (about 5% to 8% in battery charge-discharge and 15 to 18% in motor and controller losses). The high average efficiency of the diesel engine indicated by the EER is also of concern and both assumptions should be reviewed. (GROWTHENERGY2_FF56-86)

Agency Response: In response to GROWTHENERGY2_FF56-18, the cargo handling equipment efficiency of 38 percent is an operationally and hour-weighted average. Whereas staff is aware that diesel engines can operate at efficiencies of 41 to 42 percent within specific regions of the engine map, the value of 38 percent was derived from data in the current port inventory.

In response to GROWTHENERGY2_FF56-19, staff proposes the following clarifications to Table of the Attachment D: Table 1 summarizes horsepower, loads, and activity for common cargo handling equipment types. The Average engine power rating (BHP) and hours of operation are based on the Port of Long Beach 2016 Air Emissions Inventory. Hours of operation was estimated by

multiplying the number of equipment by average hours of operation in 2016. By applying load factors from CARB's inventory to the estimated hours of operation, an operational-activity weight EER can be calculated.

In response to GROWTHENERGY2_FF56-86, staff pulled load factors from the California Air Resources Board's "Cargo Handling Equipment Emissions Inventory, Appendix B". The reference for the footnote is on page 3 of Attachment D. Note that references are listed at the bottom of the page upon which they are first cited.

Staff acknowledges that other engines may operate at different efficiencies. However, staff estimates 38 percent efficiency for cargo handling equipment based on data currently available for this application. Staff is committed to re-evaluating EER value for electric cargo handling equipment if and when more relevant data become available.

Staff agrees that charging efficiency is not accounted in the EER analysis as it is not covered under EER definitions – "EER means the dimensionless value that represents the efficiency of a fuel as used in a powertrain as compared to a reference fuel used in the same powertrain." Similarly, fueling losses for other fuel applications like CNG, Gasoline, Hydrogen, etc. are also not accounted for in the EER values or in the current life cycle analyses for CI determination.

D-6.3b. Multiple Comments: *Proposed EER for Ocean Going Vessel (e-OGV)*

Comment:

- The EER for Ocean Going Vessels ("OGV") presumes all California ports will rely upon the local utility, without accounting for the fact that some ports generate their own electricity. (See *id*.)
- The EER for OGVs at berth does not account for the generation of electricity from boilers. (See *id*.)
- The EER of 2.6 for OGVs is not supported by substantial evidence in the record, as this figure does not appear to be based on any computation of electrical power generated by OGVs. (See *id*. at 3.) (GROWTHENERGY2_FF56-20)

Comment: When OGVs are "at-berth," or docked in a harbor, an auxiliary diesel engine(s) provides electrical power for equipment used while the vessel is at rest. Power needs while at-berth include support for on-board electronics, lighting, ballast pumps, ventilation systems, and air-conditioning. The ARB analysis quantifies an aggregated EER value for a wide range of auxiliary engines on all types of ships that call California ports (but does not include/pertain to boilers that are used in some vessels instead of diesel engines). The recommended EER quantifies the increased energy efficiency of using shore power instead of using the conventional on-board auxiliary diesel engine. The analysis assumes all of the electric energy would be provided by the local utility even though some California ports are able to generate a

portion of their own electricity. The potential differences in carbon intensity between power self-generated by the port and power from the grid is ignored in the EER calculation. For consistency with prior EER calculations, ARB staff also assumed that shore power is 100% energy efficient. Hence, the EER is simply the inverse of auxiliary engine efficiency, similar to the methodology used for cargo handling equipment.

Not surprisingly, the EER computed by ARB is 2.6 for OGV, which is identical to the one for cargo handling equipment. The EER estimate is based on data from a consultants' report[1] on the emissions from vessels at the Port of Long Beach, and this report lists both emissions and electric power generated by the vessels while docked. In this report, the electric power generated by ships was computed from assumptions about hoteling loads and the CO2 emission estimates were derived by using estimates of fuel consumption versus load for the auxiliary engines. Since both fuel consumption and electric power are not based on measured values but are estimated values using an assumed efficiency, the EER calculation performed by ARB uses these estimates to simply reproduce the original assumption of engine efficiency made by the consultants.

[1] Starcrest Consulting Group, Port of Long Beach 2016 Air Emissions Inventory, July 2017

In the case of OGV, the auxiliary engine provides electric power which is replaced by power from the grid, so that the ARB methodology of using of the inverse of engine efficiency for EER is defensible for OGV auxiliary power. However, the data from which the EER is estimated by ARB are not based on actual measurements but on a set of assumptions employed by the consultants to the Port of Long Beach. The ARB methodology should rely on actual data from auxiliary engine tests or actual measurements of power output and fuel consumption by OGV auxiliary engines. (GROWTHENERGY2_FF56-87)

> **Agency Response:** In response to GROWTHENERGY2_FF56-20, the comment of port-generated electricity is beyond the scope of an Energy Economy Ratio (EER) calculation. The EER provides an estimate of the diesel fuel that would be displaced when auxiliary engines are plugged in at berth. In the case where a port generates its own electricity, the port will need to submit electricity fuel pathway evaluation to quantify the carbon intensity difference from grid electricity.
>
> In general, OGVs that are configured with boilers for uses other than propulsion (e.g., heating of residual fuel, heating of cabins, or for heating of water for crew and passengers) are not capable of using their auxiliary engines to complete such non-propulsion tasks. In addition, it is not possible for the boiler to be plugged in. Therefore, staff did not consider boilers in the analysis.
>
> It is true that an EER of 2.6 was not calculated based on a direct analysis of energy consumption for OGVs at berth. The value is based on CO_2 emissions, which acts as a surrogate for fuel consumption. This approach provides an avenue for calculating power generated by the auxiliary engine. For clarity, staff provided one EER value of 2.6 to express all vessels. However, staff acknowledges the vast differences in energy consumption among various vessel

categories (e.g., cruise vessels may consume more electricity at berth than container vessels). Therefore, credit will be generated in proportion to the electricity consumed.

In response to GROWTHENERGY2_FF56-87, staff relies on the best data that was available at the time in order to develop EER values, which in this case were the data from inventory of Port of Long Beach. Staff is committed to re-evaluate EER value for OGVs when more relevant data become available. Additionally, the EER value for OGVs (2.6) is not identical to the value for cargo handling equipment (2.7).

D-6.4. *EER-Related Topics*

D-6.4a. Comment: Similarly, CARB should revise the EERs for various electricity pathways to ensure they are supported by the evidence. (GROWTHENERGY2_FF56-2)

Agency Response: Please refer to the responses to GROWTHENERGY1_B4-25a, 25d, 25e, 25g, 25h, and 25i in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

D-6.4b. Comment: To ensure the CI values assigned to electricity are based on the "best available economic and scientific information," and reliable data and methodologies, CARB should correct these issues before adopting the Proposed Amendments. (GROWTHENERGY2_FF56-21)

Agency Response: Please refer to the response to GROWTHENERGY1_B4-25k in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

D-6.4c. Comment: Attachment D to the June 20th Proposed Modifications lists EER values for Cargo Handling Equipment and Ocean-going Vessels. Limited documentation is provided for the EER values derived in Attachment D. (GROWTHENERGY2_FF56-85)

Agency Response: Attachment D is intended to be a summary of the EER analysis. The data sources used to support the analysis were indicated as references.

D-6.4d. Comment: The EER for electricity is far too high because the estimates were generated based on testing performed with accessory modes off. (GROWTHENERGY2_FF56-41)

Agency Response: Please refer to the response to GROWTHENERGY1_B4-25a in the Response to Comments on the Draft

Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

D-6.4e. Comment: The EER for electricity is also too high because it is based on optimal temperature (75°-80°) for battery efficiency, and not real world conditions. (GROWTHENERGY2_FF56-42)

Agency Response: Please refer to Response D-6.10a in Chapter IV with regards to GROWTHENERGY1_B4-75e.

D-6.4f. Comment: The EERs for numerous vehicles are overstated. (GROWTHENERGY2_FF56-43)

Agency Response: Please refer to responses to GROWTHENERGY1_B4-25a to 25j in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

D-6.4g. Comment: The Energy Efficiency ratio (EER) is the ratio of energy use by the alternative fuel vehicle to the energy used by a similar conventional vehicle per unit travel distance. The ARB has documented the EER values for several alternative fuel vehicle types in Appendix H of the 2018 Initial Statement of Reasons (ISOR) for amendments to the LCFS. H-D Systems had submitted a report which examined the EER values in Appendix H of the ISOR to assess its reasonableness using both an engineering analysis and an assessment of the similarity of vehicle types and tests used to generate the data underlying the EER. The ARB has published modifications to the ISOR in its recent June 20th proposed 15-day modifications to the original proposal detailed in the ISOR. Unfortunately, the ARB's proposed modifications have largely retained the original EER values or changed them in a directionally incorrect way, and the ARB does not appear to have reviewed the H-D Systems' report submitted in response to the ISOR. In addition, new EER values have been proposed for cargo handling vehicles at ports, and the EER for auxiliary engines in ocean-going vessels while docked at port. (GROWTHENERGY2_FF56-68)

Agency Response: Staff responded to H-D System's report in this FSOR. Please refer to Responses D-2.3c, D-6.10, and W-4 in Chapter IV regarding GROWTHENERGY1_B4-75 to B4-99, and for reasons why staff retain most of the EER values in the Proposed Modification. For electric cargo handling equipment and electricity used for ocean-going vessel, staff included supporting documents in Attachment D: Analyses Supporting the Addition or Revision of Energy Economy Ratio Values for the Proposed LCFS Amendments.

D-6.4h. Comment: The EER values for CNG vehicles do not account for the bulky tanks to carry CNG which reduce the energy efficiency of the vehicles and reduce payload capacity for cargo vehicles. (GROWTHENERGY2_FF56-69)

Agency Response: Please refer to the response to GROWTHENERGY1_B4-25c in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

D-6.4i. Comment: The EER values for battery electric vehicles do not account for the significant energy loss under cold ambient conditions and for the loss of payload capacity due to the weight of the batteries. (GROWTHENERGY2_FF56-70)

Agency Response: Please refer to the response to GROWTHENERGY1_B4-25d in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

D-6.4j. Comment: The EER values for many passenger vehicles, both light and heavy duty, do not account for the heating, ventilation and air conditioning loads that can have much more serious impacts on electric vehicle efficiency relative to conventional gasoline and diesel vehicles (GROWTHENERGY2_FF56-71)

Agency Response: Please refer to the response to GROWTHENERGY1_B4-25e in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

D-6.4k. Comment: There are inconsistencies in the proposed EER for some of the vehicle types when comparing the proposed values in relation to diesel versus gasoline vehicles. (GROWTHENERGY2_FF56-72)

Agency Response: Please refer to the response to GROWTHENERGY1_B4-25b in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

D-6.4l. Comment: The EER values for fuel cell vehicles are not consistent with vehicle fuel economy certification data. (GROWTHENERGY2_FF56-73)

Agency Response: Please refer to the response to GROWTHENERGY1_B4-25f in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

D-6.4m. Multiple Comments: ***Documents Included in the 1st 15-Day Proposal***

Comment: The earlier results are summarized in the table below from the H-D Systems report to which the values published in Table 1, Appendix A of the June 20th document have been added. As can be seen, some of the newer values have been increased rather than decreased from those published in the ISOR. ARB has not

provided any rationale for the changes and has not addressed any of the issues raised in the H-D Systems report. (GROWTHENERGY2_FF56-74)

Comment: The revisions made by ARB to the EER values in the table above are not documented in any of the appendices to the June 20th Proposed Modifications. (GROWTHENERGY2_FF56-84)

> **Agency Response:** Please refer to Responses D-6.4n to D-6.4t in this chapter with regards to GROWTHENERGY2_FF56-75 through GROWTHENERGY2_FF56-83.

D-6.4n. Multiple Comments: ***Light- and Medium-Duty EER***

Comment:

Vehicle Type	EER published in ARB ISOR	EER in Appendix A of the June 20th ARB Proposal	Suggested Correction in H-D System Report
Battery Electric Cars (LDV)	3.0	3.4	2.7, could be reduced by 10 to 15% in summer and winter

(GROWTHENERGY2_FF56-75)

Comment:

Vehicle Type	EER published in ARB ISOR	EER in Appendix A of the June 20th ARB Proposal	Suggested Correction in H-D System Report
Battery Electric Light Duty Trucks (LDT)	3.0	3.4	2.7, plus payload reduction in cargo trucks

(GROWTHENERGY2_FF56-76)

> **Agency Response:** In the current LCFS regulation, the EER for light- and medium-duty EV is 3.4. Staff did not propose to update these EERs in the Proposed Regulation Order published as part of ISOR on March 6, 2018. Please also refer to Response W-4 in Chapter IV with regards to GROWTHENERGY1_B4-92.

D-6.4o. Comment:

Vehicle Type	EER published in ARB ISOR	EER in Appendix A of the June 20th ARB Proposal	Suggested Correction in H-D System Report
Hydrogen Fuel Cell LDV	2.3	2.5	About 2.0, weather effects unknown

(GROWTHENERGY2_FF56-77)

Agency Response: In the current LCFS regulation, the EER for light- and medium-duty hydrogen fuel cell vehicle is 2.5. Staff did not propose to update these EERs in the Proposed Regulation Order published as part of ISOR on March 6, 2018. Please also refer to Response W-4 in Chapter IV in regards to GROWTHENERGY1_B4-92.

D-6.4p. Comment:

Vehicle Type	EER published in ARB ISOR	EER in Appendix A of the June 20th ARB Proposal	Suggested Correction in H-D System Report
CNG LDV/LDT	1.0	1.0	0.9 for aftermarket conversions

(GROWTHENERGY2_FF56-78)

Agency Response: Please refer to Response W-4 in Chapter IV.

D-6.4q. Comment:

Vehicle Type	EER published in ARB ISOR	EER in Appendix A of the June 20th ARB Proposal	Suggested Correction in H-D System Report
Electric TRU	3.4	3.4	ARB data too variable for conclusion

(GROWTHENERGY2_FF56-80)

Agency Response: Please refer to Response D-6.10b in Chapter IV.

D-6.4r. Comment:

Vehicle Type	EER published in ARB ISOR	EER in Appendix A of the June 20th ARB Proposal	Suggested Correction in H-D System Report
Electric Motorcycles	4.4	4.4	Probably closer to 3.5, need data

(GROWTHENERGY2_FF56-81)

Agency Response: Please refer to Response D-6.10c in Chapter IV.

D-6.4s. Comment:

Vehicle Type	EER published in ARB ISOR	EER in Appendix A of the June 20th ARB Proposal	Suggested Correction in H-D System Report
Electric Bus	4.8 at urban speed	5.0?	About 3 as an all-season average

(GROWTHENERGY2_FF56-82)

Agency Response: The EER for heavy-duty EV, including electric bus, is 5.0 in the Proposed Regulation Order published as part of ISOR on March 6, 2018. Please also refer to Response D-6.10a in Chapter IV.

D-6.4t. Comment:

Vehicle Type	EER published in ARB ISOR	EER in Appendix A of the June 20th ARB Proposal	Suggested Correction in H-D System Report
Parcel and Drayage Trucks	4 to 5.5	5.0?	Payload loss, seasonal effects and diesel idle shutoff not accounted for.

(GROWTHENERGY2_FF56-83)

> **Agency Response:** The EER for heavy-duty EV, including Parcel and Drayage Trucks, is 5.0 in the Proposed Regulation Order published as part of ISOR on March 6, 2018. Please also refer to Response D-6.10a in Chapter IV.

D-6.4u. Comment: *3. The Energy Economy Ratio (EER) table should include appropriate EERs for commercialized electric Port equipment and suitable generic EERs for other and emerging-technology equipment.* The Port is encouraged by a new EER catch-all category for eCHE in the proposed Rule, as many pieces of eCHE qualify for credit generation. However, the current generic value given is 2.7 which seems much too low for many specific types of mobile freight equipment. For example, in a CARB "Battery Electric Truck and Bus Energy Efficiency Report" dated May 2008 it showed an "EER potential range from 5.3 to 7.0 for electric yard tractors compared to similar conventional diesel vehicles." Some other pieces of equipment such as electric rubber-tired gantry cranes are commercially available and CARB could devise an EER based on their known parameters. For emerging technologies, CARB could develop a few generic EERs based on equipment size and/or capacity. Finally, the lack of appropriate and accurately derived EERs could result in fewer credits or could fail to provide enough of an economic driver for equipment conversion; thus, we encourage additional EERs to be formally adopted for specific pieces of eCHE. We support that a new EER can now be proposed for innovative technologies but caution that the extensive work and long timeline required may deter the process from being initiated. The overall EER approach should ensure that the LCFS Rule appropriately credits commercialized zero emission mobile freight equipment without restricting the inclusion and participation of early adopters of novel, electric equipment. (POLB1_FF6-4)

> **Agency Response:** As the analysis explicitly states, the EER value (2.7) is for "Cargo Handling Equipment (Non-Yard Trucks)" because staff recognizes that yard trucks have a greater EER value than non-yard truck cargo handling equipment. Yard trucks could share the same EER value (5.0) as on-road heavy-duty electric trucks. Please refer to Table 5 of the Final Regulation Order and the definition of "yard truck" in section 95481(a)(153) that clarifies that yard trucks are heavy-duty trucks.

Staff estimates the fuel efficiencies for various type cargo handling equipment based on data currently available for the applications. Staff is committed to re-evaluating EER value for electric cargo handling equipment if and when more relevant data become available.

D-6.4v. Comment: As advanced technology eTRUs come to market, we anticipate that there will be enhanced reporting capabilities to better enable the eTRU itself to serve as the FSE for LCFS purposes or to use other methods to determine electricity supplied to eTRUs. CleanFuture requests that such advanced technology eTRU technologies be evaluated in any applications for *Tier 2 Pathways for EER-Adjusted Carbon Intensity* per §95488.7(a)(3). (CF1_FF47-4)

Agency Response: Staff would like to clarify that the proposed EER-adjusted CI values can be applied only for vehicle-fuel combination not listed in the Table 5. As staff proposed an EER value of 3.4 for Electric Transportation Refrigeration Unit (eTRU), an EER-adjusted CI cannot be requested through the Tier 2 process for this vehicle-fuel combination. However, staff commits to re-evaluate and update the proposed EER values as more fuel efficiency studies and relevant data become available.

D-6.5. *Indirect Accounting for Electricity or Biomethane Used as Process Energy*

Comment: The Proposed Amendments do not allow CI reduction for dedicated renewable electricity unless the generation facilities are co-located with the fuel production facility, removing incentives for fuel producers to develop renewable sources for process energy. (GROWTHENERGY2_FF56-44)

Agency Response: Please see Response D-6.4b in Chapter IV.

D-6.6. *Clarifications for Proposed Incremental Credits for Residential EV Charging*

Comment: The bifurcation between residential and non-residential charging makes it difficult for the home charging entity to coordinate with the non-residential charging entity to encourage daytime charging. The home charging Fuel Serving Entity (FSE) has no incentive to support increases in daytime charging if the benefit goes entirely to the non-residential FSE. As the most common scenario for increasing daytime charging involves a workplace site (non-residential) and home site (residential), the bifurcation between sites may be a major obstacle to enabling access to incremental LCFS credits for smart charging. (BMW1_FF66-3)

Agency Response: Staff would like to note that the primary drivers involved in the development of EV charging infrastructure for residential and non-residential EV charging are very different and need different approaches for incentivizing investment in each category. The LCFS is modified to provide incentive to promote investment in the EV charging infrastructure for each category resulting in a bifurcation of rules for the two categories. Staff agrees that workplace EV charging ought to receive greater benefits for using the proposed smart charging pathways than residential EV charging. The LCFS provides the flexibility and

opportunity to the entities providing residential and non-residential charging to collaborate with each other or designate a single entity as the credit generator, which could result in greater efficiencies and emission reductions in some cases.

D-6.7. *Clarification of Proposed Book-and-Claim Accounting for Renewable or Low-CI Electricity*

Comment: 3. CARB should clarify in the FSOR its intent that low-CI electricity, as well as zero-CI electricity, is eligible for book-and-claim accounting. Currently, proposed Section 95488.8(i) references only "renewable electricity." CARB should confirm in the FSOR that the proposed Regulation intends to allow fuel reporting entities to use book-and-claim accounting to report low-CI electricity generally.

…

3. CARB should clarify in the FSOR that book-and-claim accounting is available for reporting low-CI electricity used for transportation

Finally, CARB should clarify in the FSOR that book-and-claim accounting is available for reporting low-CI electricity that is used for transportation, and is reported under a certified fuel pathway for electricity (either a zero-CI lookup table pathway, or a custom low-CI Tier II pathway as described above). The current proposed Section 95488.8(i) of the Regulation is inconsistent in its description of the sources to which book-and-claim accounting applies. At points, Section 95488.8(i) indicates that book-and-claim accounting is available for reporting "low-CI electricity." For example, proposed Section 95488.8(i)(1)(B) would provide that "[l]ow-CI electricity can be indirectly supplied through a green tariff program . . . . . or other contractual low carbon electricity supply relationship . . . ." Elsewhere, however, proposed Section 95488.8(i) refers instead to "renewable electricity,"[4] which is not defined. CARB should confirm in the FSOR that references to "renewable electricity" in proposed Section 95488.8(i) are intended to include all electricity from zero-CI or low-CI sources reported pursuant to a certified fuel pathway.

[4] For example, proposed Section 95488.8(i)(1), as modified by the 15-day changes, provides that "reporting entities may use indirect accounting mechanisms for *renewable electricity* to reduce the CI of electricity supplied as a transportation fuel or for hydrogen production through electrolysis, provided the conditions set forth below are met". Similarly, proposed Section 95488.8(i)(1)(B)(1) provides that "[i]n order to substantiate *renewable electricity* claims, the applicant must make contracts available to the Executive Officer . . . ." (emphasis added).

(BART2_FF32-5)

Agency Response: In response to this comment and others which indicated confusion about the meaning of low-CI and the eligibility of renewable resources, staff modified the regulation language to clarify that book-and-claim accounting is not limited to zero-CI sources, and to more consistently use "low-CI" rather than "renewable" electricity. Please also refer to Responses D-6.3. and D-6.4a in Chapter IV.

D-6.8. ***Proposed Reporting for Incremental Credits for Residential EV Charging***

D-6.8a. Comment: We interpret the 15-day modifications to allow LSEs to use telematics data as a data source to measure single family incremental LCFS credits assigned to the LSE. We believe this provides an opportunity for LSEs to explore partnerships with OEMs to generate credits for their customers, should an OEM voluntarily partner with an LSE. (BMW1_FF66-9)

> **Agency Response:** Staff would like to clarify that LSE and automaker could work together to use telematics data for reporting residential EV charging to generate incremental credits.

D-6.8b. Comment: a. clarify that Electric Distribution Utilities (EDUs) and Load Serving Entities (LSEs) must provide "revenue-grade direct metering data" for residential base and incremental credits;

…

I. Clarify that Electricity Distribution Utilities (EDUs) and Load Serving Entities (LSEs) must provide "revenue-grade direct metering data" to generate residential base and incremental credits

For residential metered EV charging, Fueling Supply Equipment (FSE) is defined in the proposed regulation as "a piece of equipment or on-vehicle telematics capable of measuring the electricity dispensed for EV charging." This suggests the definition for "metered charging" has been expanded to include other forms of data (e.g. telematics, non-revenue grade networked charger data), but it is unclear if residential charging captured by any type of FSE will now be considered "metered residential charging". This has important implications because EDUs currently must provide revenue-grade, direct metering data to generate base metered residential credits, but the proposed language suggests that EDUs can now use vehicle telematics data or non-revenue grade charger data to report "metered charging" for credits.

The same line of reasoning could be applied to LSEs, who are the first-in-line to claim both metered and non-metered residential charging incremental credits. The proposed language suggests LSEs could also use multiple types of "metered" data to claim those credits. The language also seems to suggest that LSEs could provide vehicle telematics data or non-revenue grade networked charger data for base residential credit generation. We recommend that CARB update the definitions and make it clear that EDUs and LSEs must provide revenue-grade direct metering data to generate base and incremental credits. Entities other than EDUs and LSEs can provide alternative forms of charging measurement data in accordance to the proposed credit generation hierarchy. (TESLA2_FF69-7)

> **Agency Response:** Staff would like to clarify that Electric Distribution Utilities (EDUs) are currently not required to provide electricity measured using revenue-grade meter for generating base credits for residential EV charging. Although most of the EDUs provide electricity data collected using revenue-grade

meters some EDUs provide data collected using sub-meters, which are not revenue-grade.

In section 95483.2(b)(8)(B)4., staff clarified that a Fueling Supply Equipment (FSE) for residential EV charging refers to each piece of equipment or on-vehicle telematics capable of measuring the electricity dispensed for EV charging. This means, an entity eligible for generating credit for metered residential EV charging, including Load Serving Entities and automakers, would be able to collect electricity data using a revenue-grade or non-revenue grade meter for reporting and generating credits in LCFS. Staff would like to note that any data reported in LCFS is subject to staff audit and entities reporting inaccurate information may be subject to enforcement action.

D-6.9. Multiple Comments: ***VIN as FSE for Incremental Credits for Residential EV Charging***

Comment: II. FSE Registration for EV Charging Should Not Rely on Vehicle Identification Number

eMotorWerks recognizes that FSE Registration to generate Incremental Credits from residential EV charging may require administrative enhancements. However, eMotorWerks does not support reliance on Vehicle Identification Number (VIN) as the unique identifier element for FSE registration. Residential EV charging is tied to a residence where the owner receives electricity supply, i.e., its fuel. A EV may legitimately charge at multiple locations, and a vehicle may change ownership and migrate to a new location.

In addition, VIN is not easily available to all potentially claiming parties, particularly non-EDU LSEs, which are highly likely to claim Incremental Credits through the use of metering from EV supply equipment.

CARB Staff should amend Section 95483.2 (b)(8)(B)(4) to remove the VIN requirement for FSE Registration, except for the case when vehicle telemetry is used as the metering source. (EMW1_FF45-4)

Comment: 3. CalETC opposes the 15-day modification removing an important exemption from EDUs who receive base or incremental credits for non-metered (estimated) residential charging and proposes alternative amendment language.

…

3. *CalETC opposes the 15-day modification language that removes an important exemption from EDUs who receive base or incremental credits for non-metered (estimated) residential charging and proposes alternative amendment language.*

CalETC opposes removing this EDU exemption[6] because it is infeasible for EDUs who receive estimated base residential credits or estimated incremental credits linked to green tariff to provide the fuel supply equipment name, address and GPS coordinates.

In both cases, this information is unknown. Providing a federal employer identification number (FEIN) for the EDU is possible however. And for estimated incremental credits linked to green tariff it is possible for the EDU or CCA to provide proof of EV registration and a link to a green tariff account.[7]

[6]See section 95482.1(b)(5) on page 15 of the 15-day modifications
[7]See section 95491(d)(3)(A)(6) and section 95481 (a)

CalETC suggests instead the following edits:

§ 95483.2. LCFS Data Management System:

(A) *General Requirements.* All FSE registrations must include:

1. Federal Employer Identification Number (FEIN) for the entity Registering.~~,~~

2. ~~n~~Name of the facility at which FSE is situated, street address, latitude, and longitude of the FSE location.

~~2~~ 3. Name and address of the entity that owns the FSE, if different from the entity registering the FSE.

(B) *Specific Requirements by Fuel Type.*

* * * * *

5. Fuel reporting entities for non-metered residential EV charging and fixed guideway systems are exempt from subsection (A)~~1.~~ 2 and (A) 3 above. The LRT-CBTS will assign FSE IDs for reporting purposes based on the information provided in the LRT-CBTS account registration form. (CALETC3_FF60-8)

Comment: ChargePoint acknowledges the challenge of preventing double-counting for EV charging at Single-family residences, specifically incremental credits, given the many different entities that will be able to register and generate credits. ChargePoint agrees that using one identification type is the best way to avoid double counting violations. While VIN is a piece of information that ChargePoint can gather from our EV drivers, we do not believe that it is the best information to use for FSE registration. The main issue with VIN is that it “stays” with the vehicle for the lifetime of the vehicle. Currently, many EV drivers lease EVs (given the quickly evolving technology and greater number of models available within short periods of time). It’s very plausible and perhaps even likely that an EV driver will register a station using the VIN of their current vehicle but the lease may end or the owner might sell the vehicle and get a new EV and start reporting charging off of the same EVSE but with a different vehicle, even though the registered VIN is still the same. Meanwhile, that same vehicle with the registered VIN is charging elsewhere. It would be very difficult to avoid this situation as an EVSE provider. We recommend using utility account numbers given that they are unique to both a location and resident. Additionally, it seems that EVSE are required to provide much more info than on-vehicle telematics for FSE registration. Not only is it unfairly onerous, but by not requiring on-vehicle telematics to register a location, it’s extremely

likely that vehicles will claim credits off of nonresidential and multifamily chargers. As it is, on-vehicle telematics cannot ensure the same level of protection that the chargers provide because they have don't have a fixed physical location. This can easily lead to reduced accuracy in vehicle charging attribution, which is potentially a huge source of double-counting violation. (CHARGEPOINT3_FF39-4)

Comment: II. The Collection of VIN Information Should Be Removed Because It Will Create Inconsistent Charging and Crediting Information.

Staff's Proposed Amendments would require a Vehicle Identification Number (VIN) for all FSE registrations generating Incremental Credits from single-family metered residential EV charging. This requirement is problematic for efficient and accurate LCFS reporting administration. LSEs seeking to generate Incremental Credits may not have direct access to VIN information in all cases, and may not be able to obtain and associate a VIN with metered charging information without significant administrative burden on customers and LSE staff. A more streamlined and scalable approach would be to associate credit generation with the charging, not the vehicle.

Residential EV charging occurs at a fixed location, and in the case of LSE reporting, it occurs at a single electric service account address. However, charging data from a vehicle (with unique VIN) under a single ownership may occur at multiple addresses across more than one LSE. In addition, a vehicle may change ownership (keeping the VIN) but reporting for the residential EV charging using EV supply equipment as the metered source may continue with another vehicle (with unique VIN) unbeknownst to the reporting entity. In either case, the residential EV charging is verifiable and traceable, but if another reporting entity begins reporting charging with the same VIN, it will cause an invalidation of the one or both FSE registrations by ARB.

Since residential EV charging occurs at a fixed location for one or more vehicles, with electricity supply from a single LSE, the specific reporting requirements should not rely on VIN information.[1] The ARB should amend Section 95483.2 (b)(8)(B)(4) as follows:

[1] The Smart EV Charging Group submitted a previous proposal on FSE registration requirements to address the option for different metering sources and to avoid duplication. See comments from August 7, 2017, workshop. https://www.arb.ca.gov/fuels/lcfs/workshops/09052017_smartev.pdf (Section 1.5)

For single-family residential metered EV charging, FSE refers to a piece of equipment or on-vehicle telematics capable of measuring the electricity dispensed for EV charging. Fuel reporting entities for single-family metered residential EV charging ~~using off vehicle meters~~ must provide the address of location (without abbreviations) where EV charging occurs and the service account identification number of the electricity supplier. If the fuel reporting entity is using off vehicles meters, it must provide the serial number assigned to the FSE by the OEM and the name of the equipment OEM. ~~, and the Vehicle Identification Number (VIN) for the vehicle expected to be charged at the location.~~ Fuel reporting entities using vehicle telematics must provide the VIN. This reporting is optional when reporting metered electricity to generate base credits. (SEVCG3_FF61-3)

Comment: PG&E recommends that ARB clarify the Fueling Supply Equipment (FSE) registration requirements for metered EVs when reported by the EDUs for generating base residential EV charging credits.

In the draft regulation text, *§95483.2(b)(8)(B)(4)* indicates that FSE registration for metered residential EVs should include the Vehicle Identification Number (VIN) for the vehicle expected to charge at the residence (and the serial number of the charging equipment if off-vehicle meter data is used for the reporting), but notes that this information is optional when reporting metered electricity for base credits. However, it is unclear if all other FSE registration information, which includes name and address of the FSE owner, is also optional for metered EVs when reporting electricity for base credits. PG&E recommends that ARB clarify the FSE registration requirements for EDUs reporting from metered EVs for generating base credits.

Furthermore, when clarified by ARB in the draft regulation text, PG&E recommends that FSE registration for metered EVs should not include name and address of the metered EV customer, or any other private customer information, when reporting for base credits. PG&E recommends using the current approach, as this does not disclose private customer information and does not risk any double counting since this would be for base credits only, which are designated to the EDU. (PGE2_FF64-8)

Comment: The requirement for automakers to provide the VIN should be eliminated to avoid unnecessary reporting of personally-identifiable information. The purpose of collecting this data from OEMs is to eliminate the potential for double counting between data submitted by OEMs and that of LSEs. We recommend that CARB staff consult with stakeholders to consider alternative solutions to address double counting. (BMW1_FF66-4)

Comment: c. require VIN-level reporting only for the first-in-line credit generators to minimize the administrative burden on pathway participants and limit the sharing of sensitive information.

…

III. Require VIN-level reporting only for the first-in-line credit generators to minimize the administrative burden on pathway participants and limit the sharing of sensitive information

The proposed language includes a requirement for all 0-CI and smart charging credit generators to provide VIN-level reporting data. However, reporting requirements for existing LCFS pathways have minimized the sharing of sensitive personally-identifiable information, protecting consumer data privacy and reducing administrative burden for stakeholders. To remain consistent with this principle, we ask CARB to only require VIN-level reporting from entities that are the first-in-line credit generators.

As automakers are not first-in-line credit generators, they should be able to provide the aggregated charging data across their fleet of vehicles. A VIN-level reporting requirement for automakers would be substantially more burdensome than for other

parties due to the sheer volume of charging records. Furthermore, CARB has DMV registration information that could be used to determine how much, when and where each individual is charging if paired with comprehensive VIN-level charging data from automakers.

The first-in-line credit generators would report VIN-level charging information, which can then be subtracted from the total charging amount (in kWh) provided by the relevant manufacturers of those EVs, eliminating the risk of double-counting. There is precedent for this approach within the LCFS program; credits that an electric forklift operator claim directly are subtracted out from the total forklift credits given to EDUs. (TESLA2_FF69-9)

> **Agency Response:** As part of the 15-day changes, staff proposed modifications to section 95483.2(b)(8)(B)4. to clarify that Fueling Supply Equipment (FSE) registration for residential EV charging is optional when reporting metered electricity to generate base credits.
>
> Multiple entities, including but not limited to, CCA's, automakers, and charging network providers can claim incremental credits for providing low-CI electricity for residential EV charging. Staff believed that creating a hierarchy and effective reporting requirements were necessary to prevent any double counting of incremental credits. Therefore, staff proposed registration of the FSE for reporting metered electricity to generate incremental credits. Staff proposed opt-in entities reporting metered electricity for generating incremental credits must register an FSE by providing the Vehicle Identification Number (VIN) of the vehicle expected to be charged and if an off-vehicle equipment is used for measuring electricity then the unique serial number assigned by the Original Equipment Manufacturer (OEM) and the name of the OEM must also be provided. After careful consideration of several options, including utility customer ID, VIN, home address, geolocation, etc. staff determined VIN is the most readily available unique identifier that can be used for FSE registration without creating reporting complexity and raising data privacy concerns. VIN is a standardized unique ID that all customers are well aware of and can be supplied as publicly available information if not paired with any personal owner information. Whereas other options like utility customer ID are not standardized and are not easy to locate for each customer. Further, staff clarified that location information and address is not required to register FSE for reporting residential EV charging to ensure customer privacy.

D-6.10. Multiple Comments: *Proposed Hierarchy for Incremental Credits for Residential EV Charging*

Comment: ChargePoint recommends amending the prioritization of the incremental credits for EV charging at Single-family residences. Our understanding is that the goal of these incremental credits is to encourage more charging when there is benefit to the grid and/or there is lower carbon of the electric fuel, smart chargers enable EV drivers to easily participate in charging that meets these goals. Currently, the hierarchy does not

acknowledge the differences in sources of metered data and the associated quality of the data as well as omits opportunities for EVSEs to capture credits outside of programs with LSEs. ChargePoint recommends the following hierarchy:

1. The Load Serving Entity (LSE) supplying electricity to the EV associated with the FSE ID and metered EVSE data has first priority to claim credits;
2. The Load Serving Entity (LSE) supplying electricity to the EV associated with the FSE ID and metered on-vehicle telematics data has second priority to claim credits;
3. The manufacturer of the EVSE associated with the FSE ID has third priority;
4. The manufacturer of the EV associated with the FSE ID has fourth priority; and
5. Any other entity has fifth priority.

It is imperative that ARB aligns its goal of reducing CI with the hierarchy for residential credits—different sources of data have greater quality and ability to shape charging behavior. For example, our chargers are tested to operate with the same accuracy as utility meters, which requires stringent measurement standards specific to energy metering. To participate in the California IOU sub metering pilot and SDG&E utility programs, ChargePoint chargers were test by SDG&E, PG&E, Nexant, and an independent lab. ChargePoint and other networked charging companies are naturally integrating with third-party Distributed Energy Resource Management Software (DERMS) providers that utilities and grid operators already utilize for grid optimization and demand response, and thus smart chargers can communicate more directly with utilities and grid operators than telematics.

Additionally, the consumer experience and ability to shape consumer behavior for EVSE is superior compared to on-vehicle telematics. The user experience of networked home level 2 chargers is simple and easy. Often, setting schedules and attempting to otherwise manage EV charging through the vehicle or manufacturer's mobile app is confusing and can impede public charging. For example, nighttime charging schedules set via the vehicle sometimes conflict with the driver's ability to charge at a public charging station on-the-go, because the vehicle has been directed not to charge except for the nighttime hours. Additionally, the user experience of managed charging, software/mobile app functionality, and integrations vary significantly by EV model and EV manufacturer. Thus, incentivizing networked home level 2 EVSEs provides a better driver experience. (CHARGEPOINT3_FF39-1)

Comment: I. <u>The Incremental Credit Hierarchy Should Be Revised To Promote Adoption, Customer Engagement Innovation and Grid Integration</u>

At the direction of the Board, Staff has proposed a hierarchy for assigning Incremental Credits for residential EV charging at single-family residences. eMotorWerks supports prioritization.

Where the LSE is not generating Incremental Credits, there is no basis for prioritizing one metering source over another. A major rationale for granting LSE prioritization is

the direct relationship with electricity supply. All other entities would be similarly situated in this respect.

The proposed prioritization will stifle innovation in financing and customer engagement. A supplier of EV infrastructure and metering cannot create a customer offer, based on LCFS value, to reduce the cost of equipment or commit to offset the cost of EV charging if at any moment, after registering the Fueling Station Equipment (FSE) with CARB for Incremental Credits, an EV manufacturer can attempt to register the EV and displace the current fuel reporting entity.

eMotorWerks asserts that when initiating the Incremental Credits component of the LCFS regulation, CARB must not ignore customer choice in the prioritization, as noted by at two parties in the June 11 workshop, and should equalize the prioritization of metered sources to generate Incremental Credits, by identifying either manufacturer of the EVSE or EV as equally eligible to claim Incremental Credits in Section 95483(c)(1)(B)(2), based on customer choice.

If CARB is not willing to equalize eligible for metered sources as a general rule, then CARB should prioritize those entities that submit not only metered information per FSE, but also the accurate and reliable hourly interval metering as proposed under the "EV Grid - Smart Charging" pathway - as information only, unless "Smart Charging" Incremental Credits are also sought by the Fuel Reporting Entity. This would provide incremental value to CARB in analyzing the carbon intensity of these new Incremental Credits, and it would be a step toward grid-integration of EV charging, which should be the long-term interest of the LCFS regulation.

The utilization of networked EV charging data and capabilities is at the core of the Joint Agencies California Vehicle-Grid Integration Roadmap, developed in coordination with CARB.[1] eMotorWerks has called for greater alignment with actual carbon intensity from the beginning of the informal stakeholder process to update the LCFS regulation. Those entities that can assist CARB and the state to meet the goals of the California Vehicle-Grid Integration Roadmap should be prioritized.

[1] https://www.caiso.com/Documents/Vehicle-GridIntegrationRoadmap.pdf

If CARB chooses to prioritize hourly interval metering, the incremental credit hierarchy should be amended through the following amendments to Section 95483(c)(1)(B):

> Incremental Credits. Any entity, including an EDU, is eligible to generate incremental credits ~~(in addition to the base credits)~~ for improvements in carbon intensity of electricity used for ~~residential~~ EV charging at single-family residences. ~~An EDU that generates incremental credits must meet the requirements set forth in paragraphs 2. through 5. in section 95491(d)(3)(A).~~ Multiple claims for incremental credits for metered residential EV charging associated with a single FSE ID will be resolved pursuant to the following order of preference:
>
> 1. The Load Serving Entity (LSE) supplying electricity to the EV associated with the FSEID and metered FSE data has first priority to claim credits;

2. Any entity authorized by residential FSE owner or operator and technically capable to supply the hourly quantity of charging based on metered records, as required by§95491.(d)(3)(B).

3. Any other entity designated by residential FSE owner or operator to supply the quantity of charging based on metered records. (EMW1_FF45-2)

Comment: I. The Incremental Credit Hierarchy Should Be Revised to Provide LSEs and EVSPs with Greater Certainty Regarding the Impact of Subsequent Incremental Credit Claims by a Higher Ranked Entity.

The Smart EV Charging Group supports staff's efforts to provide certainty and clarity in the incremental electric vehicle (EV) charging credit (Incremental Credit) provisions through a "crediting hierarchy." However, the hierarchy as contemplated in the Proposed Amendments should be further amended to provide certainty to entities that are seeking to market products and programs in reliance on future Incremental Credit awards.

If the Proposed Amendments are adopted, a supplier of EV infrastructure and metering will have difficulty providing a customer offer, based on LCFS value, to reduce the cost of Fueling Supply Equipment (FSE) or commit to offset the cost of EV charging if, at any moment, after registering the FSE with the ARB for Incremental Credits, an EV manufacturer attempts to register the EV and displace the current fuel reporting entity.

Similarly, a community choice aggregator (CCA) may endeavor to develop new public programs and/or offer customers point of sale or other forms of upfront incentives based on expectations of LCFS revenues from an incremental credit pathway. In order to ensure predictable funding for CCA programs, CCAs need to know that they will be guaranteed the incremental credits for a time period sufficient to facilitate EV incentive program(s), and that another LSE or manufacturer will not supplant the CCA's eligibility for LCFS credits during the program period.

Under either outcome, an entity providing direct financial support for the adoption of an EV and/or ongoing cost-effective operation of an EV or EVSE would see the LCFS credit revenue anticipated to support the financial incentive provided evaporate. This outcome would undermine the good work of CCAs, EV infrastructure and metering companies, and others in supporting EV adoption.

To address these concerns, the ARB should guarantee that once an opt-in entity has begun claiming incremental credits for a registered FSE, the opt-in entity will not be supplanted by a higher ranked entity for a period of at least one year. A longer term would allow for more robust upfront/point of sale incentives and would also be stable. Frequent changes in credit allocation will mean no single entity providing incentives can maximize these funds by relying on a longer-term revenue stream as a means to drive incentives. In addition, the incremental credit hierarchy should be expanded through the following amendments to Section 95483(c)(1)(B):

Incremental Credits. Any entity, including an EDU, is eligible to generate incremental credits ~~(in addition to the base credits)~~ for improvements in carbon intensity of electricity used for ~~residential~~ EV charging at single-family residences. ~~An EDU that generates incremental credits must meet the requirements set forth in paragraphs 2. through 5. in section 95491(d)(3)(A).~~ Multiple claims for incremental credits for metered residential EV charging associated with a single FSE ID will be resolved pursuant to the following order of preference:

1. The Load Serving Entity (LSE) supplying electricity to the EV associated with the FSE ID and metered FSE data has first priority to claim credits;

2. The LSE supplying electricity to the EV associated with the FSE ID and metered on vehicle telematics data has second priority to claim credits;

3. The manufacturer of the FSE associated with the FSE ID has fourth priority;

4. The manufacturer of the EV associated with the FSE ID has ~~second~~ fifth priority; and

5. Any other eligible entity has ~~third~~ fifth priority.

…

The ARB should endeavor to create a hierarchy that provides a degree of certainty for entities seeking to make customer offerings and develop programs based on the anticipated incremental credit revenue. (SEVCG3_FF61-2)

Comment: The hierarchy for generating single family residential incremental LCFS credits may limit participation from OEMs because it does not provide a clear, upfront indication as to whether a household is already being counted by the LSE through one of its programs. Absent a simple, clear way to determine which households are counted by LSEs, OEMs will not have strong incentive to enroll customers in a smart charging program. We recommend that CARB staff consult with stakeholders to consider ways to modify the LSEs eligibility as the first order in the hierarchy to enable greater participation from OEMs and simpler processes for identifying households that might participate. (BMW1_FF66-6)

Comment: Section 95491 seems to mean that two applications for receiving smart charging credits for the same vehicle would result in neither entity receiving credits. According to section 95491(d)(3)(B)(2)(c)(page 92): "Only a single entity can generate incremental credits for smart charging for the same FSE. If two or more entities report for the same FSE to generate incremental credits, no incremental credits will be issued for that FSE." As a vehicle or a charging station can bean FSE, there may be cases where both the charging station and the vehicle claim incremental LCFS credits for smart charging. In this case, the hierarchy described in Section 95483(c)(1)(B) should be used to determine the allocation of credits. We do not interpret the language on page 92 to supersede the allocation hierarchy for incremental LCFS credits in Section 95483(c)(1)(B). (BMW1_FF66-8)

Comment: Amend § 95483 (c) (1) (B) to read:

> (B) *Incremental Credits*. Any entity, including an EDU, is eligible to generate incremental credits for improvements in carbon intensity of electricity used for EV charging at single-family residences. Multiple claims for incremental credits for metered residential EV charging associated with a single FSE ID, <u>where no clear contractual record can be found,</u> will be resolved pursuant to the following order of preference:

Rationale:

The original wording was unclear and could be read to imply that any claim made by a Load-Serving Entity, would automatically be resolved in its favor regardless of clear documentation that incremental credits were assigned elsewhere. This is particularly problematic as it concerns smart charging credits. The decision to modify charging behavior in order to obtain these credits may be facilitated by a third party, by provision of information, a device or software to the vehicle owner. We anticipate that load serving entities will attempt to incentivize smart charging behavior, but they may not be the only entity to do so. Since the behavioral changes required to maximize smart charging are made by vehicle owners and drivers, they should have an opportunity to assign the credits as they see fit. The proposed change recognizes that and ensures that LSEs or EV manufacturers cannot unilaterally override the driver or owner's preferences. This change also supports the suggested amendment to § 95483 (c) (1) (A), above. (NEXTGEN3_FF65-6)

Comment: b. establish a hierarchy for residential smart charging credits to provide clarity for the multiple entities who participate in this pathway; and…

…

II. Establish a hierarchy for residential smart charging credits to provide clarity for the multiple entities who participate in this pathway

Unlike the incremental credits for 0-CI electricity, it seems like CARB has not proposed a hierarchy for claiming smart charging credits. When multiple entities report the same FSE data for residential smart charging credits, which could be either directly metered charging data, vehicle telematics or data from other charging equipment, no entity would receive the credits. The lack of certainty would make it very difficult for any entity to offer smart charging programs to consumers because no entity would know if they will receive smart charging credits for a customer. CARB can avoid this situation by establishing a similar hierarchy as the 0-CI charging credits. To be the first-in-line credit generator, an entity would provide smart charging data with the customer's permission and VIN so it can be subtracted from a comprehensive total provided by the relevant automaker. (TESLA2_FF69-8)

> **Agency Response:** The intent of incremental credit is to incentivize use of low-CI electricity for residential EV charging. Although utilities receive base credits for residential EV charging based on the California average grid electricity

CI value, staff believes there is a potential to promote use of lower carbon electricity for residential EV charging. Staff proposed to issue incremental credits for improvement in CI of electricity as compared to the California average grid CI when used for residential EV charging. Any eligible entity that can demonstrate CI improvement of electricity over the grid average CI—either by using book-and-claim accounting for low-CI electricity or by using a smart charging pathway—could generate incremental credits for the same electricity used for generating residential base credits. This means several entities could be eligible to claim incremental credit for same electricity—including but not limited to: automakers, CCAs, charging providers, and EDUs. Therefore, staff proposed a hierarchy for claiming incremental credits to prevent double counting among several entities capable of providing low-CI electricity for residential EV charging.

Staff proposed that the LSE, including CCAs and utilities, supplying the low-CI electricity has the first priority to claim credits as long as they can provide metered EV charging data for the purposes of credit generation. Staff believes LSE are the primary fuel providers for residential EV charging and are well-suited to provide low-CI electricity. Requiring metered data through LSE's would also provide charging network providers opportunity to install charging equipment at residences in coordination with LSEs, facilitating better monitoring and reporting of charging data. LSE would also be able to collaborate with automakers to use telematics data for making such claims.

Since all LSEs may not be able to provide low-CI electricity option to EV drivers, EV manufacturers will have second priority, as they are well equipped to leverage telematics for promoting smart charging or provide low-CI electricity through indirect book-and-claim accounting. Any other entity that can provide metered data and demonstrate sufficient low-CI electricity has the third priority to claim incremental credits as long as no other entity above in the hierarchy is making the claim. This would allow maximum flexibility to promote low-CI electricity for residential EV charging.

The commenter also suggests in SEVCG3_FF61-2 that a time guarantee must be provided that once and entity starts generating incremental credits it cannot be supplanted by another eligible credit generator higher in the proposed hierarchy. Staff did not propose any such time guarantee as that would be in conflict with the proposed hierarchy and could create reporting complexity. Staff would like to clarify that an eligible entity could continue generating incremental credits as long as it meets all the necessary reporting and recordkeeping requirements and no other entity higher in the hierarchy is making the same claim. If an entity with a higher priority registers an FSE to claim the incremental credits, then any other entity generating incremental credits for the same FSE would no longer be eligible to receive credits for those FSE and would be notified by CARB. Staff believes the proposed hierarchy allows entity the opportunity and flexibility to collaborate with other entities to ensure they continue to receive incremental credits for long-term as they invest in promoting use of low-CI electricity for residential EV charging.

In further response to suggested hierarchies in CHARGEPOINT3_FF39-1 and SEVCG3_FF61-2, staff believes the stakeholders' proposed frameworks may not be effective in avoiding duplicate claims as several entities may end up with same priority and creating any additional priority levels in the hierarchy would only result in reporting complexities.

D-6.11. Multiple Comments: *Proposed Credit Generator for Multi-Family Residential EV Charging*

Comment: ARB Staff proposed in the 15-Day Modification that residential EV charging be separated into single-family residences and multi-family residences categories. For EV charging at multi-family residences, ARB proposes that the owner of the FSE or its designee is the first in line to generate credits and EDUs will receive credits not claimed by any other entity. The majority of residential customers in LADWP's service territory are renters and live in multi-family residences, and LADWP forecasted that 85% of new residential buildings units will be multi-family residences. With this proposal, LADWP can potentially lose a majority of its residential based credits. LADWP has an EV charger rebate, which is funded through residential based credit proceeds and provides a larger incentive to commercial customers such as multi-family residences. LADWP believes that it is in the best position to provide EV incentives targeted to customers that are renters in multi-family residences, and recommends that ARB remove the distinction between single-family and multi-family residences. (LADWP2_FF10-4)

Comment: 1. EV Charging at Multi-Family Residences: The LCFS 15-Day Notice proposes to differentiate between single-family residences (SFRs) and multi-family residences (MFRs) in assigning EV charging credits. Specifically, the proposed changes would assign all EV charging credits (base and incremental) to the owner of the fueling supply equipment at MFRs, rather than providing it to the Electrical Distribution Utilities (EDU). While we appreciate the intent of this change, which is to incentivize the installation of charging at MFRs, we believe it unnecessarily complicates the residential EV charging program and substantially dilutes the value of residential EV charging credits all to the determent of other programs that could have a more immediate and lasting impact on the PEV market. Consequently, we do not support this change and recommend eliminating it. (AAMGA1_FF18-2)

Comment: 2. Calculation of Credits for EV Charging Using Fuel Pathways: The proposed language, within the 15-Day notice under Section 95486.1, for Incremental Credits for Residential EV Charging utilizes the phrase "Residential EV Charging." Residential EV Charging stems from the draft language proposed by CARB in April but does not account for the revisions applied to the LCFS 15-Day Notice, which removes this phrase and subsequently uses new nomenclature titled "Charging at Single-Family Residences"(SFRs) and "EV Charging at Multi-family Residences" (MFRs). As noted above, we recommend deleting the distinction between multi- and single-family residences. However, if ARB proceeds with this distinction, this Section should be modified to specify SFRs and MFRs accordingly to convey the true scope of incremental credits. (AAMGA1_FF18-3)

Comment: ChargePoint strongly supports EV Charging at Multifamily Residences as a separate category from residential charging collectively, which previously included both single-family and multi-family. Multi-family charging can often be located in the "visitor", "mixed-use", or "common" areas of a multi-family residence, which are closer to "non-residential" in the usage. Without separation, it could be an area of significant verification confusion if vehicles can register credits from chargers with multiple users, including non-residents, given the many changes proposed in the residential EV charging modifications to LCFS. We believe that this modification to the proposed regulations will facilitate faster deployment of EV charging infrastructure in multifamily residences, which is arguably the most challenging location within the built environment to bring EV infrastructure. We commend ARB Staff for making this change to hopefully bring more EV charging to Multi-family residents, and thus bringing more equity to clean technology. (CHARGEPOINT3_FF39-3)

Comment: V. <u>The Smart EV Charging Group Supports Multi-Family Charging Credit Provisions.</u>

The Smart EV Charging Group supports establishing EV Charging at Multifamily Residences as a separate category. This would change the current regulations, which treat residential charging as a single category that includes both single-family and multi-family charging. Multi-family charging equipment can often be located in the "visitor", "mixed-use", or "common" parking areas of a multi-family residence, which are closer to "non-residential" in access and usage. Without separation, multi-family charging could be an area of significant verification confusion if vehicles can register credits from chargers with multiple users, including non-residents, given the many changes proposed in the residential EV charging provisions of the LCFS regulations. We believe that this simple and straightforward modification to the Proposed Amendments will help avoid confusion and facilitate faster deployment of EV charging infrastructure in multi-family residences, which are arguably the most challenging locations within the built environment for installation of EV infrastructure. We commend ARB staff for making this change to bring more EV charging to Multi-family residents, and thus bringing more equity to clean technology. (SEVCG3_FF61-6)

Comment: <u>eMotorWerks Supports Multi-Family Charging Credit Provisions.</u>

eMotorWerks supports EV Charging at Multi-family Residences as a separate category from residential charging collectively, which previously included both single-family and multi-family. This modification to the proposed regulations will facilitate faster deployment of EV charging infrastructure in multi-family residences, which is one of the most challenging locations to provide with EV infrastructure. (EMW1_FF45-7)

Comment: We appreciate the consideration to allow the owner of fuel supply equipment (FSE) at multi-family properties to opt in to generate LCFS credits. (SREC2_FF53-1)

Comment: CalETC largely supports the proposed 15-day modifications the LCFS draft regulation order, with the notable exception of the provisions on multi-unit dwellings and removal of an EDU exemption. (CALETC3_FF60-3)

Comment: 1. CalETC opposes the 15-day modification replacing EDUs as the 1st in line to generate "base" credits for residential charging at multi-unit dwellings.

…

1. CalETC opposes the 15-day modification replacing EDUs as the 1st in line to generate "base" credits for residential charging at multi-unit dwellings; the modification effectively takes away LCFS credit value that is currently allocated to EDUs.[3]

[3] See Section 95483 (c)(1) and (2), section 95481 (a),

The CARB Board gave clear direction to staff in support of a statewide point-of-purchase new vehicle rebate (POP rebate) funded with LCFS residential base credit revenue. Taking away the utilities' access to multi-unit dwelling credit value directly conflicts with the Board direction, creating uncertainty in the revenue stream needed to fund a POP rebate program and/or limiting the POP rebate program to only Californians who do not live in multi-unit dwellings. Uncertainty in the revenue stream to fund the POP rebate program would reduce the effectiveness of the POP rebate program, particularly at a time when the state and the utilities are committed to making electric vehicles available to all, including those residing in multi-unit dwellings. Excluding Californians who reside in multi-unity dwellings from the POP rebate program raises equity concerns. It is imperative to increase access to electric vehicles for residents of multi-unit dwellings, and the POP rebate program is intended to help accomplish this imperative. However, if LCFS residential base credits associated with multi-unit dwellings do not support the POP rebate program, the POP cannot reliably support POP rebates for residents of multi-unit dwellings. A successful POP rebate program requires sufficient revenue and should be accessible to all Californians, whether or not they live in a multi-unit dwelling.

Residents in multi-unit dwellings benefit from charging where they live, as do electric vehicle drivers who live in single-family homes. The LCFS program should not distinguish residential credit value, and the benefits offered by that residential credit value, based on the type of residence and electric vehicle driver occupies. CalETC respectfully requests the LCFS provisions on this topic return to the text shown in the 45-day notice in March 2018. (CALETC3_FF60-6)

Comment: SMUD supports continuation of the Electricity Distribution Utility (EDU) as the credit generator for electric vehicle (EV) charging at multi-family residences because EDUs are in the best position to economically install chargers.

In the "Notice of Public Availability of Modified Text and Availability of Additional Documents and Information," issued by staff on April 20, 2018 ("Notice of Modified Text"), staff suggests that granting owners of Fueling Supply Equipment (FSE) first priority to claim residential electricity credits for vehicles charging in multi-unit dwelling situations would incent faster deployment of charging infrastructure because charging

equipment at multi-family residences are more similar to non-residential charging than to charging at single-family residences.

SMUD opposes the 15-day Modifications to treat credit generation from residential EV charging in multi-family residences differently than for single-family EV charging. Subdividing residential charging into single and multi-family categories adds considerable complexity to residential electricity credit generation, and forms a barrier to the Board requested “point of purchase” program. Multi-family living situations take many forms in this state, so it cannot be assumed that charging equipment at multifamily residences are more similar to non-residential charging than to charging at single family residences. Much of the housing stock that qualifies as multi-family dwelling are triplexes and other joint housing that are not part of classic garden style or high rise apartment complexes.

Moreover, the economic self-interest of owners of large multi-family dwellings will remain a barrier to purchasing EV charging equipment for tenants until adoption of EVs is sufficiently widespread.

In addition, splintering residential credit generation into multiple categories would reduce credit revenues overall given that some multi-family dwelling property owners would delay getting into the market, which could damage existing EDU programs that have been found to incent EV adoption, such as SMUD’s Free Fuel for 2 Years program, and consumer-forward advertising and outreach programs which are aimed at all residential customers (both single family and multi-family dwelling residences). (SMUD2_FF63-2)

Comment: PG&E disagrees with the current proposal in draft language §95483(c)(2) that owners of EV charging equipment at multi-family residences will generate the LCFS credits from multi-family residential EV charging, instead of the EDU. This change would reduce the residential EV charging credits generated by EDUs, and thus negatively impact the EDUs’ ability to administer programs funded by LCFS credits from residential EV charging to benefit all EV drivers.

Under the current regulation, EDUs receive credits from residential EV charging, including charging from both single-family residences and multi-family residences, and use the proceeds from these credits to benefit EV drivers. The credit calculation for non-metered residential EV charging is based on the count of EVs in each utility’s territory and does not distinguish between single-family or multi-family residences. Per direction from ARB at the April 27 Board hearing on LCFS, the utilities are currently discussing ways in which to create a statewide, point-of-purchase EV incentive funded by the revenue from these residential EV charging credits. If residential EV charging credits from multi-family residences were no longer given to the EDUs, the credit revenue available to fund this point-of-purchase incentive could be significantly lower. Furthermore, the point-of-purchase incentive should be available to all Californians from all residence types, and therefore multi-family residential EV charging credits should be handled consistently with single-family residential credits.

PG&E recommends that the EDUs continue to generate all residential EV charging base credits, from both single-family and multi-family charging, such that the credits are handled consistently regardless of residence type and can contribute to the statewide point-of-purchase EV incentive program currently under discussion. (PGE2_FF64-4b)

Comment: b. maintain the existing crediting structure for residential multi-unit dwelling (MUD) charging.

…

II. Maintain the existing crediting structure for residential multi-unit dwelling (MUD) charging

Given the statewide point-of-purchase EV rebate from residential base credits is underdevelopment, we recommend that staff not separate residential charging credits for MUDs from single-family homes at this time. (TESLA2_FF69-11)

> **Agency Response:** Please see Response D-6.15a, Proposed Credit Generator for Multi-Family Residential EV Charging, in Chapter IV.

D-6.12. *Pathways Available for Reporting Non-EV Charging Applications Using Electricity as a Transportation Fuel*

D-6.12a. Multiple Comments: Pathways Available for Reporting Non-EV Charging Applications Using Electricity as Transportation Fuel

Comment: *2. Carbon Intensity Values (CI) from Renewables and Time-of-Use Charging should be applicable to mobile freight, electric cargo-handling equipment (eCHE) and Auxiliary Power for Ocean-Going Vessels (OGV) At-Berth.* Currently, book-and-claim accounting for excess renewables, renewables purchased through a green tariff program or PPA, or on-site renewables apply just to "electricity supplied as a transportation fuel." The Port does not believe that CARB intended to exclude electric cargo-handling equipment or electric auxiliary power engines for OGVs at-berth, from utilization of a lower CI for use of renewable energy. Modifying the rule to clearly include these applications for use of the lower CI associated with renewable energy would provide certainly for Port operators and fleet owners who are considering expensive upgrades or changes to their equipment. (POLB1_FF6-3)

Comment: *5. The usage of Renewable Energy CI Values should be allowed for CHE and Auxiliary Power for Ocean Going Vessels At-Berth.* Currently, book-and-claim accounting for excess renewables, renewables purchased through a green tariff program or PPA, or on-site renewables apply just to *transportation* fuels. The Port does not believe that CARB intended to exclude electric cargo-handling equipment or electric auxiliary power engines for ocean-going vessels at-berth, from utilization of a lower carbon intensity (CI) for use of renewable energy. Modifying the rule to clearly include these applications for use of the lower CI associated with renewable energy would provide certainty for Port operators and fleet owners who are considering expensive upgrades or changes to their equipment. (POLB1_FF6-6)

Comment: However, further changes are necessary to clarify that fixed guideway systems may claim electricity fuel pathways in the lookup table, and may use book-and-claim accounting for low-CI electricity reporting: (BART2_FF32-1)

Comment: 1. CARB should further modify the Regulation to clarify that both lookup table electricity fuel pathways, and book and claim accounting, are available to fuel reporting entities other than on-road electric vehicles.

…

1. CARB should modify the proposed LCFS Regulation further, and re-circulate for another 15-Day comment period, to make clear that lookup table pathways for electricity are not limited to electricity used for charging on-road EVs, and that fuel reporting entities other than on-road EVs may use book-and-claim accounting for reporting low-CI electricity use.

While CARB staff have indicated informally to BART that the lookup table pathways for electricity will be available to fixed guideway systems, the 15-day text still limits those pathways to electricity used for EV charging. Fuel pathways ELCG and ELCR are described in Table 7-1 as applying only to electricity "supplied to electric vehicles in California." References to these fuel pathways throughout the proposed Regulation, as well as references to the use of book-and-claim accounting of electricity, similarly refer only to electricity dispensed to electric vehicles. As explained in BART's prior comments, the Regulation currently defines the term "electric vehicle," or "EV," to include only battery-electric and plug-in hybrid on-road vehicles ("BEVs" and "PHEVs," respectively); the term "electric vehicle" or "EV" does not include fixed guideway systems or other off-road modes of electric transportation. CARB should modify the text of the Regulation to make it clear that fuel reporting entities may use those pathway codes for electricity uses in transportation modes other than on-road EV charging, such as fixed guideway system operation.

Specifically, CARB should modify the current draft regulatory language as follows, and re-circulate for another 15-day comment period:

- Modify the first sentence of proposed Section 95488.5(d)(1) as follows:

  Annual Update to California Average Grid Electricity Pathway. In order to reflect the rapidly evolving portfolio of electricity generating resources in California, the Executive Officer will update the "California Average Grid Electricity ~~Supplied to Electric Vehicles~~" Lookup Table pathway CI value on an annual basis.

- Modify proposed Section 95488.5, Table 7-1, to change the description of electricity fuel pathways ELCG and ELCR as follows:

  ELCG: California average grid electricity ~~supplied to electric vehicles in California~~

ELCR: Electricity that is generated from 100 percent zero-CI sources ~~supplied to electric vehicles in California~~.

Similarly, CARB staff have indicated informally to BART that fixed guideway systems may use book-and-claim accounting to report low-CI electricity used for public transportation. Yet, proposed Section 95488.8(i)(1)(A) of the Regulation refers only to electricity "dispensed to electric vehicles." Again, because the term "electric vehicle" is defined to include only on-road vehicles such as BEVs and PHEVs, CARB should modify proposed Section 95488.8(i)(1)(A) to refer more generally to electricity "dispensed for use as a transportation fuel." Specifically, CARB should:

- Modify proposed Section 95488.8(i)(1)(A) as follows:

  Reporting entities may report electricity dispensed ~~to electric vehicles~~ <u>for use as a transportation fuel</u> or as an input to hydrogen production (including for purposes of the Renewable Hydrogen Refinery Credit) as renewable electricity without regard to physical traceability if it meets all requirements of this subarticle. The renewable electricity must be supplied to the grid within a California Balancing Authority (or local balancing authority for hydrogen produced outside of California). Such book-and-claim accounting for renewable electricity may span only three quarters. If a renewable electricity quantity (and all associated environmental attributes, including a beneficial CI) is supplied to the grid in the first calendar quarter, the quantity claimed for LCFS reporting must be matched to grid electricity dispensed ~~to electric vehicles~~ <u>for use as a transportation fuel</u> or for hydrogen production no later than the end of the third calendar quarter. After that period is over, any unmatched renewable electricity quantities expire for the purpose of LCFS reporting.

These changes are necessary to reconcile the above-identified provisions with other existing and proposed provisions of the LCFS Regulation that (a) authorize fixed guideway systems to generate credits for the use of electricity as a transportation fuel, and (b) authorize book-and-claim accounting for electricity used as a transportation fuel more generally, without limiting book-and-claim accounting to EV charging. For example:

- Existing Section 95483(e)(6) provides that "[f]or transportation fuel supplied to a fixed guideway system, the transit agency operating the system is eligible to generate credits for electricity used to propel the system."
- Proposed Section 95488.8(i) authorizes the use of book-and-claim accounting "for renewable electricity to reduce the CI of electricity supplied as a transportation fuel", without limiting book-and-claim accounting to EV charging.

These proposed changes would affirm CARB's longstanding policy of equitably treating on-road and off-road modes of electric transportation in the LCFS program. This policy was made clear in the 2015 Initial Statement of Reasons for the LCFS Regulation, which notes that the Board directed Staff, in Resolutions 09-31 and 11-39, to pursue credit generation for electricity used to fuel off-road transportation, as well as on-road

EV use.[1] Similarly, the 2015 Final Statement of Reasons for the LCFS Regulation states that "Use of *electricity* for transportation, not use of particular *equipment*, is what LCFS incentivizes."[2] (Emphasis in original.) CARB should not deviate from these principles now by affording special treatment to on-road electric vehicles. BART's fixed guideway system provides a proven and low-cost mode of low-CI electric transportation throughout the Bay Area, and should have its investment in low-carbon fuel supply recognized in the same manner as on-road EVs.

[1] *Staff Report: Initial Statement of Reasons for Proposed Rulemaking* (December 2014) ("2015 ISOR") at ES-14.

[2] *Final Statement of Reasons for Rulemaking, Including Summary of Comments and Agency Response* (October 2, 2015) ("2015 FSOR") at 980.

(BART2_FF32-2)

Comment: In addition to the regulatory changes identified above, CARB should also clarify in the FSOR that the lookup table pathways ELCG and ELCR will be available to fuel reporting entities that operate fixed guideway systems. (BART2_FF32-6)

Comment: San Francisco appreciates the efforts of CARB to update the LCFS regulation. As noted in previous comments, San Francisco's primary concerns are that electrified public transit that uses "fixed guideways" (such as Muni) is treated similarly to other transportation sources, such as electric and hydrogen-powered vehicles, for purposes of having their lower carbon intensity (CI) reflected in the LCFS calculations, and that all zero-CI resources be eligible for the LCFS program.

San Francisco had requested in its initial comments that:

- "fixed guideway systems" be eligible to use the Lookup Table Pathway in Section 95488.1(b)(2)(A);

…

<u>"Fixed Guideway Systems" should be eligible to receive LCFS credits based on participation in a Green Tariff program</u>

The SFPUC provides 100% GHG-free electric energy to over 300 electric overhead-catenary (trolley) buses, 150 light rail vehicles (LRVs), and over 40 cable cars that are part of the Muni fleet, one of the largest electrified public transit fleets in the country. These zero-GHG vehicles operate on "fixed guideway systems," as defined in Section 95481(a)(35) of the current LCFS regulation.

As noted in San Francisco's initial comments, eligibility to use the Lookup Table Pathway continues to refer only to "electric vehicles", the definition of which excludes fixed guideway systems. There is no reason that an electric bus using zero-CI energy from the grid (as San Francisco's buses do) should be treated differently from an electric bus utilizing an electric battery or hydrogen-fueling.[1]

[1] See, Comments of the City and County of San Francisco on CARB's Proposed Revisions to California's Low Carbon Fuel Standards, and attachment (dated April 23, 2018).

(CCSF3_FF51-1)

Agency Response: Please refer Response D-6.20, Fuel Pathway Available for Reporting Electricity Used for Non-EV Charging Transportation Applications, in Chapter IV.

D-6.12b. Comment: In addition, ARB should confirm that procurement activities to support Low-CI EV charging reporting can be performed by third parties under contract with the Fuel Reporting Entity, so long as invoices or reports confirming transactions, including renewable attribute retirements, can be provided to ARB, as required. (SEVCG3_FF61-4b)

Agency Response: Staff would like to clarify that intent of proposed requirements is to ensure that entity claiming low-CI electricity can unequivocally demonstrate that REC or any environmental attribute associated with the claimed electricity was retired on its behalf, specifically for the LCFS purpose. Staff is committed to working with stakeholders to implement the effective tools and necessary procedures for implementing the reporting requirements.

D-6.12c. Comment: VI. <u>The Smart EV Charging Group Supports the Ability of CCAs to Submit Tier 2 Applications for Incremental Credits, Relying on Carbon Intensity Information of their Entire Portfolio.</u>

The Proposed Amendments would provide a CCA or other LSE with an option to generate incremental credits by demonstrating that the LSE has provided charging energy though a green tariff or other contractual agreements for low-CI electricity. The requirements for these fuel pathway applications are specified in Section 95488.8 and include, among other things, that the LSE has procured renewable energy above and beyond the RPS and has not used the RECs attributable to those resources (i.e., above and beyond the RPS) for purposes of RPS compliance. The Smart EV charging group supports these proposed amendments and seeks to clarify that through a Tier 2 application, an LSE could establish a pathway based on information sources other than those explicitly listed in Section 95488.8 (i.e., REC and contract data). An LSE may wish to leverage carbon intensity information of its entire portfolio (not just particular contracts) through a Tier 2 application. The Smart EV Group understands that the LCFS regulations, as amended, would allow the Executive Officer to exercise discretion in the consideration of additional carbon intensity information. For example, the Executive Officer could consider a Tier 2 Fuel Pathway based on WCI Carbon Registry information, CEC Power Source Disclosure data, or other information sources provided the information submitted by the LSE reasonably substantiates the carbon intensity associated with the LSE's entire portfolio to the satisfaction of the Executive Officer. (SEVCG3_FF61-7)

Agency Response: Please see Response D-6.5e in Chapter IV.

D-6.12d. Comment: Green Tariff programs (§§ 95486.1(c)(2)(A)(1), 95486.1(C)(1)(a), and 95488.8(i)(1))

SMUD continues to support the option in the Proposed Amendments of linking non-metered EV residential charging to EDU green tariff programs, but seeks clarification in the 15-day Modifications that incremental credits can be claimed for low-CI energy procured for its existing programs.

SMUD currently sponsors two green pricing programs that meet the definition of a Green Tariff program under the 15-day Modifications. SMUD's Greenergy program allows customers to purchase up to 100% of their load from Green-e certified renewable energy through a flat monthly fee on their utility bill. SMUD supplies Greenergy from eligible renewable energy resources that meet the renewables portfolio standard (RPS) procurement requirements of section 399.30 of the Public Utilities Code with both RPS eligible renewable energy resources located within California and RPS-eligible unbundled renewable energy credits (RECs) from Green-e certified resources in the Western Interconnection. In addition, SMUD's SolarShares program allows customers to pay monthly subscriptions to acquire a "share" in a solar power generation resource located in California. Our SolarShares customers also pay a flat fee to acquire kilowatt hours (kWh) of solar generation that vary with the season, with greater bill credits produced in sunny months than in winter months. In the case of Greenergy, SMUD supplies a portion of the program with 100% zero-CI electricity from facilities it owns or contracts with for delivery in California and procures zero-CI attributes for the remainder. In the case of SolarShares, all of the electricity is generated from zero-CI sources that serve California.

Proposed section 95486.1(c)(2)(A)(1) directs the Executive Officer to award incremental credits to EDUs for non-metered, residential EV charging by customers on Green Tariff programs such as Greenergy and Solar Shares. CARB would issue incremental credits for non-metered residences shown to receive zero-CI electricity based on the same method of estimation used to calculate base credits. However, section 95486.1(c)(2)(A)(1) adds a proviso that the credits would be issued so long as the zero-CI electricity "is not claimed by another generator of incremental low-CI electricity credits using metered data." This phrase suggests the possibility that if third party is able to meter the zero-CI electricity, it could claim the incremental credits for zero-CI electricity purchased by the Greenergy or Solar Shares customer. Ambiguity around who is first in line to generate incremental credits from Green Tariff programs, whether it's parties who pay for the zero carbon fuel versus third parties who meter it, creates uncertainty that would be a disincentive to EDUs and their customers. The incremental value of low or zero carbon fuel should go to the party responsible for generating it and supplying it to EV owners. Instead, it appears that staff could be favoring parties that meter low carbon electricity over those who make it.

In contrast, staff has recognized that ambiguity around claims to incremental credits for metered charging at single-family residences should be resolved. The 15-day Modifications in section 95483(c)(1)(B) state that Load Serving Entities (LSEs) that meter residential charging have first priority to claim credits, manufacturers are second in line, and all other entities have third priority. According to staff, there are several reasons for this hierarchy. First, LSEs "are assigned first priority because they have the clearest ability to quantify the supply of low carbon electricity to the customer under

existing California energy policy, including through green tariff programs." (Notice of Modified Text, p. 5.) Second, staff asserts that the ability of LSEs to facilitate smart charging to support the electric grid merits priority, but also recognizes the value of onboard telematics to meter EV charging and potentially enable V2G.

Ambiguity around claims to incremental credits for non-metered charging at single family residences is even more problematic than for metered charging because most residential charging is unmetered. As SMUD and other utilities have commented in the past, insisting on metering at single-family homes is an unnecessary expense because quantifying the supply of electricity to EVs can be done quite accurately by current formula in section 95486.1(c)(1)(A). If the estimation method in that subsection is good enough to calculate base credits, it should be good enough to calculate incremental credits. In addition, the first rationale for granting the LSE priority in the metered residential EV charging context is equally true for non-metered EV charging: EDUs or LSEs have the "clearest ability to quantify the supply of low carbon electricity to the customer …" because they purchase zero-CI electricity on their behalves. Not only should paying a premium for zero-CI fuel entitle the customers to priority, but the outlay of the extra funds means that the utility will quantify how much zero-CI fuel is acquired and delivered to its customers. A third party may know how many kWh go into the vehicle but it does not know how much zero-CI is in the kWhs. (SMUD2_FF63-3)

> **Agency Response:** To prevent double counting, each entity claiming incremental credit for residential EV charging must register the Vehicle Identification Number (VIN) associated with the EV that is claimed to be charged at the residence. If an entity were claiming incremental credits based on metered electricity quantity associated with a particular VIN, no incremental credits could be generated associated with that VIN based on the non-metered quantity.
>
> If no entity is claiming incremental credits based on metered data associated with a VIN then the Executive Officer shall use the formula in 95486.1(c)(1)(A) for calculating the quantity of electricity eligible to generate incremental credits for the EV associated with that VIN, if the EV is shown to receive low CI electricity.

D-6.12e. Comment: SMUD also requests clarification of a key requirement in section 95488.8(i)(1)(B)(1). Subsection (i) enables EDUs to use book-and-claim accounting to claim low-CI or zero-CI electricity supplied through green tariff programs such as Greenergy and SolarShares. Paragraph (B)(1) of that subsection states that "Electricity [must be] generated using equipment owned by, or under contract to the pathway applicant for all environmental attributes of the claimed electricity." SMUD interprets this text to mean that the EDU (or LSE) must own the low-CI resource, such as a solar PV facility, or its low-CI attributes in order for those attributes to generate incremental credits through a Green Tariff program. SMUD seeks clarification that in the context of EV charging by customers of EDU Green Tariff programs, if the utility satisfies this and the other requirements of (B)(1), it is the only party that may generate incremental credits from the claimed electricity. This would be appropriate because, as stated above, the party that generates or buys the low-CI electricity should be the one to benefit from making it. (SMUD2_FF63-4)

Agency Response: The LSE must be a co-applicant for a pathway application requesting low-CI electricity based on a green tariff program. Once the application is approved, the certified CI could be used by all the co-applicants for reporting purposes in the LRT-CBTS.

D-6.12f. Comment: As SMUD commented previously, the Proposed Amendments create a complicated system of requirements to ensure that Greenergy or SolarShares customers who purchase low-CI electricity are the same customers who are charging EVs at home or at a participating workplace. Instead, the customer who pays for low-CI electricity through a green tariff should only need to register the EV with the EDU with a proof of registration within some period of time after purchase or lease. Once that link is established to ensure that the EV owner is a green pricing customer, and the EV is not registered to another EDU, the LCFS program can generate more incremental credits to monetize the value of low-CI charging. SMUD urges staff to accept the hierarchy that the EDU should have priority to generate credits from zero carbon intensity (0g/MU) electricity provided to EDU customers of green pricing programs such as Greenergy and SolarShares. (SMUD2_FF63-5)

Agency Response: The entity that is capable of furnishing metered charging data is entitled to priority over non-metered data when making claims for incremental credits. When an entity reporting metered charging data for electricity supplied to registered FSE, through contracting for environmental attributes and/or through a green tariff program, then the incremental credits for that FSE will be provided to the entity making the claim with the metered charging data. If there is no incremental credit claim based on metered data or non-metered data for a registered FSE (determined by the VIN), then the LSE may claim the incremental credits based on the quantity of electricity calculated and allocated to the LSE using the formula found in section 95486.1(c)(1)(A). For claiming incremental credit for non-metered residential EV charging, the LSE must be able to provide, upon request of the Executive Officer, the VIN for each electric vehicle claimed and evidence of EV vehicle registration and low-CI electricity supply at the same location.

D-6.12g. Comment: 2. CARB should confirm in the FSOR its intent that fuel reporting entities may submit a Tier II application to seek a certified CI for electricity procured from low-CI electricity sources, such as Asset Controlling Suppliers.

…

2. CARB should confirm in the FSOR that fuel reporting entities may submit a Tier II application for low-CI electricity sources such as Asset Controlling Suppliers.

Proposed Section 95488.1(b)(2), as modified by the 15-day changes, lists various renewable electricity sources that are identified as having a CI of zero, including solar photovoltaic, wind, solar thermal, small hydroelectric facilities of 30 megawatts or less, ocean wave, ocean thermal, and tidal current. Proposed Section 95488.1(d)(4) allows fuel reporting entities to submit Tier II applications for “[e]lectricity pathways not found in

the Lookup Table." BART appreciates that the proposed Regulation now recognizes a broader list of zero-CI electricity sources, including small-scale hydroelectric facilities. However, the proposed Regulation remains vague as to how CARB will treat Tier II pathway applications under proposed Section 95488.1(d)(4) for other low-CI electricity sources that have a CI significantly lower than grid average, but that are not listed as zero-CI sources in proposed Section 95488.1(b)(2).

Fuel reporting entities should be incentivized to procure electricity for their transportation fuel from low-CI sources, even if those sources are not listed in proposed Section 95488.1(b)(2). Incentivizing fuel reporting entities to invest in electricity supply portfolios that have significantly lower CIs than the grid average, even though not from zero-CI sources listed in proposed Section 95488.1(b)(2), is entirely consistent with the goals of the LCFS program, which according to CARB is "designed to decrease the carbon intensity of California's transportation fuel pool and provide an increasing range of *low-carbon* and renewable alternatives."[3] However, in order to make such investments in low-CI electricity procurement, fuel reporting entities must have confidence that the low-GHG characteristics of such purchases will be recognized by CARB in the Tier II process.

[3] 2015 ISOR at I-2 (emphasis supplied).

For example, the proposed Regulation does not make clear how CARB would evaluate the CI of electricity purchases from Asset Controlling Suppliers, which themselves operate a diverse portfolio of resources, and are assigned a single emissions factor by CARB for purposes of the California Cap and Trade Program. As detailed in BART's prior comments on the proposed LCFS changes, there is currently limited publicly available information about the underlying sources in ACS portfolios. Still, ACS purchases clearly represent a form of electricity with a CI factor well below the grid average. The LCFS should clearly and unambiguously incentivize the purchase of electricity from such sources.

In informal discussions with BART, CARB staff have expressed their intent that BART will be permitted to file a Tier II application seeking a single custom CI representative of BART's low-CI electricity portfolio, including its ACS purchases. Given that this is not clearly expressed in the current proposed regulatory text, CARB should confirm its intent in the FSOR that fuel reporting entities may seek a custom CI for a diverse electricity portfolio through the Tier II process, and may use the best publicly available information to describe the CI of low-CI sources, including ACS purchases. CARB should further clarify in the FSOR that the best available information about the CI of electricity sourced from an ACS may be the emissions factor assigned to the ACS portfolio by CARB under the Cap and Trade and Mandatory Reporting Regulations. (BART2_FF32-4)

> **Agency Response:** BART is invited to apply for Tier 2 Pathway Approval for power purchased through an ACS. This will require the applicant to provide all records to substantiate the pathway as required under section 95488.7. As per 95488.7(a)(2)(A)(7):

> "A quantitative discussion of the thermal and electrical energy consumption that occurs throughout all phases of the fuel life cycle over which the applicant exercises control. All fuels used (natural gas, biogas, coal, biomass, etc.) must be identified and use rates quantified. The regional electrical energy generation fuel mix used in the CA-GREET3.0 analysis must be identified. Internally generated power such as cogeneration and combined heat and power must also be described. All fuel pathway applicants using grid electricity must choose electrical generation energy mixes from among the subregions in CA-GREET3.0, if applicable. The options include the 26 subregions defined in eGRID2014v2, and a national grid mix for Brazil and Canada. Applicants whose fuel production facilities or feedstock source regions are located in an area for which there is no corresponding subregion included in CA-GREET3.0 must enter user-defined energy resources and submit the source of the data utilized to the Executive Officer for approval."

To quantify and identify the electrical energy generation fuel mix, a joint application with the ACS may be necessary to provide site-specific data to calculate a valid generation mix. This is detailed in section 95488(b). Additionally, section 95488.8(i) provides additional requirements for claiming low-CI electricity under an approved Tier 2 pathway:

> "generation invoices or metering records are required to substantiate the quantity of low-CI electricity produced from the renewable assets. Monthly invoices must be unredacted copies of originals showing electricity sourced (in kWh) and contracted price;"

Upon submission of all necessary records and invoices regarding generation sources and quantity of electricity purchased, the Executive Officer will attempt to replicate the CI calculation using the CA-GREET3.0 model, pursuant to section 95488.7(d)(4). The emissions factor assessed by CARB for use in the MRR cannot be used as a substitute for the Executive Officer's determination of the CI of electricity purchased from an ACS as the MRR does not employ life cycle accounting.

D-6.13. *Proposed Smart Charging and Smart Electrolysis*

D-6.13a. Comment: PG&E continues to support ARB's inclusion of Smart Charging Lookup Table Pathways. However, consistent with our previous comments, we recommend that ARB address two important issues to prevent the incentive for EV charging and electrolytic hydrogen load to shift to times when their impact on GHG emissions is worse than if a California grid-average value were used:

a) Smart charging carbon intensities (CI) should accurately reflect actual curtailment and marginal heat rates,

b) Smart charging carbon intensities should align with EV Charging Rates.

a) PG&E remains concerned that the proposed smart charging CIs do not accurately reflect curtailment and marginal heat rates, and mischaracterize the electricity CI at certain times in the table. Specifically, the simplified curtailment data source currently used in the table does not distinguish between periods of local curtailment, where EV charging and electrolytic hydrogen load outside the local curtailment pocket result in increased GHG emissions, and periods of system curtailment, where EV charging and electrolytic hydrogen load result in zero marginal GHG emissions. The current curtailment data over-estimates the impact of curtailment on marginal GHG emissions, and under-estimates the marginal emissions during the middle of the day, when local curtailment is most prevalent.

At the same time, the smart charging CIs do not accurately reflect the differences between marginal heat rates of thermal generation (and therefore the CI of electricity) at different times of the day and different seasons. For example, during the middle of the day (9 AM-3 PM) and the middle of the night (midnight-6 AM), efficient combined cycle generators are typically running, so the CI of electricity should be low even when renewables are not being curtailed. In contrast, during the late afternoon and evening (4 PM-9 PM), less efficient 'peaker plants' may be running, so the CI of electricity is typically higher. This is in alignment with current or proposed time-of-use (TOU) rates for the investor-owned utilities (IOUs), which have a peak period between 4 and 9 PM based primarily on marginal generation costs and driven by these heat rate factors. The ARB proposed 4 PM-9PM CIs are actually lower than midnight-6 AM CIs, and if implemented would incent EV charging during the most emissions-intensive time period.

We recommend that ARB consider adopting the methodology for calculating marginal GHG emissions described in the 2016 Itron/E3 Self-Generating Incentive Program (SGIP) Evaluation Study[1], or alternatively the similar methodology employed in the updated Avoided Cost Calculator (ACC Model)[2] to calculate the marginal emissions impact of EV charging and electrolytic hydrogen production.

[1] Available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454964

[2] Available at http://www.cpuc.ca.gov/General.aspx?id=5267

The Itron methodology was used in all three IOUs 2018 Rate Design Window (RDW) applications to model the impact of default rates on GHG emissions and is also being used by the GHG Signal Working Group that was established by CPUC Ruling 12-11-005[3]. The Itron methodology calculates marginal GHG emissions from actual real-time prices in the California Independent System Operator (CAISO) energy market. The calculation of marginal GHG emissions is expected to be updated once a quarter as part of the process pursuant to this Working Group, which could support ARB's quarterly updates to the smart charging Pathway CIs.

[3] Available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M202/K276/202276301.PDF

PG&E's alternate suggestion, the ACC Model, has been used in many cost-effectiveness proceedings to calculate the benefits of demand-side resources based on generation costs and avoided greenhouse gases, and was most recently updated in the Integrated Distributed Energy Resources (IDER) proceeding (R. 14-10-003). The methodology used in the ACC Model is almost identical to the Itron

methodology, except that it uses day-ahead instead of real-time prices and is updated less frequently.

b) PG&E reiterates its concern that the smart charging pathway CIs listed in Table 7-2 do not align with the TOU periods established in the IOUs EV charging rates. To support consistency between times with the lowest CIs and times with the lowest rates, we suggest that ARB compare the smart charging pathway CIs with the TOU periods in the utilities' EV rates whenever the CIs are updated. (PGE2_FF64-5)

> **Agency Response:** Please refer to Response D-6.1i in Chapter IV.

D-6.13b. Comment: IV. <u>The Smart EV Charging Group Recommends an Audit Requirement for Session Level Data.</u>

ARB should require that any reporting entity for EV charging maintain, make available and have duly authorized ability to make auditable records of EV charging for each FSE reporting EV charging. If telematics data is used for reporting, geolocation of each reported charging session must also be providable. (SEVCG3_FF61-5)

> **Agency Response:** Staff agrees with the commenters that entity generating credits using smart charging pathways must be able to provide documentation showing the quantity of electricity per FSE used for EV charging during a reporting period broken down by hourly windows upon request by the Executive Officer.

D-6.13c. Multiple Comments: ***Clarification for the Proposed Smart Charging and Smart Electrolysis***

Comment: We believe that the most effective way to deliver incremental LCFS credits from electric vehicle smarting charging is to increase the amount of charging that occurs during the daytime hours when solar is highest on the grid. BMW is exploring this as a use case in a smart charging pilot using drivers in the San Francisco Bay Area and working with PG&E to provide incentives and communication strategies to increase charging during daytime hours. To ultimately be effective at increasing charging during the day, BMW and PG&E provide incentives to customers to shift their charging from nighttime to daytime hours. As this requires new messaging and new forms of customer incentives, CARB should allow parties to experiment with programs that can increase daytime charging. CARB should modify the proposed rules to allow LSEs the flexibility to create programs that incentivize daytime charging and allow utilities to capture the Incremental LCFS credits from these programs. These programs should allow OEMs and charging stations to contribute to daytime charging on a voluntary basis. (BMW1_FF66-2)

Comment: The existing counting rules for residential charging seem to provide a relatively smaller incentive for residential daytime charging relative to a non-residential site providing daytime charging. The rules appear to require a home site to report all its charging events, including nighttime charging, in order to calculate how many incremental LCFS credits it gets from smart charging. This means its daytime charging will be averaged out against its nighttime charging. A non-residential charging site, particularly a workplace site, will likely

have less nighttime charging. This means that its daytime charging will be averaged against lower amounts of relatively high carbon-intensity (CI) charging, resulting in a higher incentive to participate in smart charging. Given the high nighttime CI rates and the assumed requirement to report all charging events, it is not clear that a residential charging FSE would have an incentive to participate in the incremental LCFS program using the smart charging methodology. Clarifying that smart charging CI does not average out against high nighttime CI hours would create more value for participating households, resulting in more emissions reductions attributed to the incremental LCFS program. This can be accomplished by modifying the rules to allow FSEs to report any charging hours they wish to count toward the incremental credits and not require all charging hours. (BMW1_FF66-5)

> **Agency Response:** Staff proposed the smart charging pathway to promote shifting of EV charging load to the times when marginal emission of grid electricity are lower than the annual grid average emission. Staff understands that EV charging at non-residential locations is less likely to happen during the times of higher marginal emissions of grid electricity and vice versa for residential EV charging; however, the smart charging pathway for both residential and non-residential EV charging is based on the same principle. Staff believes a framework that recognizes higher CI values during high emission periods and lower CI values during low emission periods will provide a stronger signal to shift EV charging for greater grid benefits and GHG emission reductions.

D-6.13d. Comment: The regulation provides an hourly emissions factor to measure the benefit of smart charging. CARB should allow LSEs to provide an alternative hourly emission factor if such a factor is based on the time-variant energy delivered by the LSE. (BMW1_FF66-7)

> **Agency Response:** Staff proposed a Lookup Table pathway for smart charging that is intended to represent appropriate CI values by 24 hours of the day averaged for each quarter across California as a whole. Allowing Load Serving Entity (LSE) to request specific smart charging CI values might create complexities related to fuel pathway application evaluation, quarterly reporting, and potential audit of electricity data reported using such smart charging pathway. However, staff would be open to considering this issue further in future rulemakings if parties actively demonstrate continued interest in LCFS rewards for smart charging.

D-6.14. *Requirements for Entities Generating Credits for Supplying Electricity as a Transportation Fuel*

Comment: 6. CalETC supports the 15-day modification requiring non-EDU electricity fuel credit generators to meet similar requirements placed on EDU electricity fuel credit generators.[1] CalETC requests this section be amended to require the electricity fuel

LCFS credit generator provide the owner of the fuel supply equipment (FSE)[2] basic information about the LCFS program and value of LCFS credits.

[1] See 95483 (c) (3)(C) and § 95491 (d)(3)(A) in the 15-day modifications

[2] I.e., the charging station

…

6. CalETC supports the 15-day modification requiring non-EDU electricity fuel credit generators to meet similar requirements placed on EDU electricity fuel credit generators.[9] CalETC requests this section be amended to require the electricity fuel LCFS credit generator provide the owner of the fuel supply equipment (FSE)[10] basic information about the LCFS program and value of LCFS credits.

[9] See 95483 (c) (3)(C) and § 95491 (d)(3)(A) in the 15-day modifications

[10] I.e., the charging station

CalETC believes that credit generators for non-residential and residential charging should have substantially similar requirements and believes the proposed amendments to § 95483 (c)(3)(C) and § 95491 (d)(3)(A)[11] in the 15-day modifications achieve this goal. In addition, CalETC also supports the 15-day modifications that allow the owner of the fuel supply equipment (FSE) for non-residential charging to designate another party to take on the role of credit generator,[12] but further request that the designee also be required to provide the FSE owner with a clear, high level explanation of the LCFS program, its value to the EVSE owner and why CARB has created the LCFS regulation. See CalETC's April 23 comment letter for additional reasons why CalETC supports these changes (e.g., better consumer and site host experience, protecting against fraud).

[11] See pages 12 and 91 of the 15-day modifications.

[12] See section 95483 (c) (3)(C) on page 12 of the 15-day modifications.

(CALETC3_FF60-11)

Agency Response: Staff appreciates the commenter's support for the proposed modifications requiring non-EDU electricity fuel credit generators to meet similar requirements placed on EDU electricity fuel credit generators and providing a credit generator flexibility to designate a third party on its behalf. However, staff does not believe it is necessary to require that a credit generator provide the owner of the Fuel Supply Equipment (FSE) basic information about the LCFS program and value of LCFS credits. The owner of the FSE would be the default credit generator or would have contractually designated a third party to be a credit generator on its behalf. In either case, the commenter's recommendation is not necessary.

D-6.15. ***New Electric Transportation Applications***

D-6.15a. ***Clarification for the Proposed New Transportation Applications***

Comment: *4. Allow fleet operators to use the same simplified calculations that CARB uses on behalf of electrical distribution utilities to calculate credits.* The requirement to keep track of the battery capacity rating, depth of discharge, charger efficiency rating,

and charge return factor can be complicated and cumbersome for some equipment operators at the Port, which may be why none have elected to opt into the program. Allowing the same simplified calculation that CARB staff uses would likely improve participation of the Port and terminal operators. This proxy method of recording electricity used is similar to the proposed calculation to calculate the renewable energy from residential non-metered electric vehicle charging. The Port strongly encourages adoption of this calculation for equipment, to simplify crediting and reduce the cost and physical footprint of metering equipment required. (POLB1_FF6-5)

> **Agency Response:** Under the current rule, acceptable reporting methods for measuring electricity used in electric forklifts include the option to estimate electricity using a CARB-approved quantification methodology based on battery capacity rating, measured depth of discharge, charger efficiency rating, and charge return factor. This method will continue to be applicable under the new rule.
>
> For other non-forklift charging applications at ports, the electricity must be measured or metered using a Fueling Supply Equipment (FSE) that needs to be registered prior to reporting electricity for credit generation. Staff believes most of the equipment using electricity for transportation applications at ports either already have acceptable separate meters or can afford to install separate meters for monitoring and reporting electricity, given the potential magnitude of LCFS credit value that could be generated annually. Staff doesn't believe that extending the estimation methods used for residential charging of light-duty EVs is appropriate for port applications.

D-6.15b. Multiple Comments: ***Fuel Reporting Entity and Credit Generator for Proposed New Electric Transportation Applications***

Comment: *7. The Port supports the transfer of ownership of LCFS credits in certain circumstances.* In some instances at the Port where the two are distinct entities of fleet operator and fleet owner, the fleet operator is often contracted to manage the equipment and does not have an equity stake in it. The Port supports the proposed amendment language for electric forklifts and other eCHE which provides the fleet owner with the credit that will help properly incentivize the upgrade of equipment from diesel to electric, because this type of upgrade is significantly less feasible without the added value and benefit of the LCFS credit. The opportunity to designate another entity to be the credit generator is also advantageous for ease of reporting and operational complexities.

With regards to the ownership of the credit for shore power, the Port looks forward to reviewing that language once released. It is suggested that the credit generator and owner for this activity be the owner of the fueling supply equipment (FSE), just as EV charging stations receive credit for vehicles charged at their site under the Rule. Since the Port and terminal operators must invest in significant infrastructure in order to allow vessels to charge, this award of credits would help overcome barriers to the installation and utilization of stationary and mobile shore power infrastructure. Permitting the owner

of the shore power infrastructure to generate and claim the credits will enable the value of the credits to be possibly passed through more readily to the vessel and fleet operators without subjecting them to the burdensome reporting requirements that may not be economically feasible for them, dependent upon the number of port calls their fleets make in California each year.

To review, the fact that the Port nor any port terminal operators are currently generating LCFS credits suggests that the current Rule did not provide enough incentive for the industry to become involved and subject itself to the potentially burdensome reporting and verification requirements. The changes in the proposed amendments to the Rule that allow for more eCHE and like equipment at the Port to qualify for generation and for credits to be transferred from a fleet operator to an aggregator are encouraging, but the complexity of crediting and high cost of electric equipment replacement will likely continue to prevent a high level of engagement unless the suggestions above are addressed in the final amendments. These revisions and clarifications could aid the industry in participating in the LCFS program, enabling the Port and its terminal operators to begin transitioning towards zero emission equipment while retaining cost-effective operations in the increasingly competitive world of maritime goods movement. (POLB1_FF6-8)

Comment: The current language in section § 95483 (c)(6)(A), states that *"[f]or electricity supplied to eTRU, eCHE, or eOGV, the owner of the eTRU, eCHE, or eOGV is the fuel reporting entity and the credit generator for electricity supplied to each respective unit."* This language is potentially confusing since "fuel reporting entity" does not appear to be a defined term and appears to equate equipment owner with electric meter owner, which may not always be the case.

PMSA proposes that language be modified to read *"[f]or electricity supplied to eTRU, eCHE, or eOGV, the owner of the eTRU, eCHE, or eOGV is the credit generator for electricity supplied to each respective unit and shall satisfy fuel reporting requirements to the State."* In this way, it will be clear that the credit generator is the owner of the eTRU, eCHE, or eOGV. Since it is the equipment owner who makes decisions of equipment deployment and usage, the owner is responsible for the decisions that CARB wishes to incentivize.

The credit generator should not be identified as the owner of the charging infrastructure, typically the port authority, who does not make deployment or use decisions, whose investment in electrical infrastructure is typically recouped from the equipment owner through the equipment owner's lease with the port authority, and whose initial investment was often already subsidized by the State of California (e.g., Proposition 1B funding). (PMSA1_FF14-2)

> **Agency Response:** Staff appreciates the commenters' support and suggestions for designating the credit generators for the proposed new electric transportation applications. As part of the second 15-day changes, staff proposed that the owner of the Fueling Supply Equipment (FSE) be the eligible entity for generating credits for supplying electricity to electric transport refrigeration units (eTRU),

electric power to ocean-going vessels (eOGV), and Electric Cargo Handling Equipment (eCHE). This is consistent with other electricity categories where the first fuel reporting entity and credit generator is the FSE owner. Further, the FSE owner would have the option to designate any other entity to be a credit generator on its behalf, should that be the best fit for their business model.

D-6.15c. ***EER Values for New Electric Transportation Applications***

Comment: TRUs on shipping containers should use the energy storage device as the FSE. All TRUs on shipping containers are electric powered for temperature control while onboard ships. Diesel-powered TRU gensets are used to provide power to TRUs on shipping containers while in transit over the road.[2] TRU battery packs for on-road use for TRUs on shipping containers displaces diesel fuel which is consistent with the intent of LCFS. On the other hand any electricity used in electric refrigerated container racks at ports and terminals is not displacing diesel fuel use and should not be eligible for LCFS crediting.

[2] Q&ATRU Gensets. https://www.arb.ca.gov/diesel/tru/documents/q&a_tru_genstes.pdf

(CF1_FF47-5)

Agency Response: Staff would like to clarify that the proposed Energy Economy Ratio (EER) value proposed for the Electric Transportation Refrigeration unit (eTRU) is tailored for the on-road and rail eTRU applications. Any eTRU on board an Ocean-going Vessels at-berth (eOGV) would not be eligible to generate credits for using electricity on the vessel using the EER and reporting requirements for eTRU. However, if the OGV at-berth with TRU were using shore power to displace the auxiliary engine power then the electricity would be eligible to generate credits using the EER and reporting requirements for eOGV.

For on-road eTRU, each unit would need to be registered as an FSE. An eligible entity could generate credits for electricity supplied to eTRU as long as all the reporting and FSE registration requirements are met.

D-6.15d. ***FSE Registration for Electric Transportation Refrigeration Unit***

Comment: At this stage of TRU electrification market development for trucks, trailers, and rail cars, the terms “Fueling Supply Equipment” and “FSE” should refer to the equipment that supplies electricity to the eTRU instead of the eTRU itself. The capability of data capture from the legacy eTRUs in use today is limited in some eTRU models and non-existent in other eTRU models. Currently, the equipment that can best capture eTRU usage data is the sub meter. The sub meter also serves as an aggregating point for all TRU electric outlets and is the most efficient way to track electricity usage in eTRU units. (CF1_FF47-3)

Agency Response: Staff would like to clarify that each Electric Transportation Refrigeration Unit (eTRU) unit must be registered as FSE for reporting electricity usage. However, the electricity can be measured using an on-board or a separate meter and the eTRU unit itself need not need be equipped to measure

electricity usage. However, upon request from the Executive Officer, the reporting entity must be able to provide documents supporting the reported information in the LCFS program.

D-6.16. *Point-Of-Purchase Rebate*

D-6.16a. Multiple Comments*: General Support for a Statewide Point-of-Purchase Rebate Program*

Comment: The Board instructed the Executive Officer to "[e]xplore with stakeholders the opportunities to increase the magnitude of ZEV vehicle rebates funded by [the] sale of LCFS credits." We agree that using revenue from the sale of LCFS credits to support a statewide point of sale rebate would effectively accelerate transportation electrification. As stakeholders, we are eagerly awaiting an opportunity to review and comment on these opportunities. (UCS3_FF28-2)

Comment: Regarding statewide point-of-purchase new electric vehicle rebates, we support the need for additional to-be-determined amendments in the second 15-day modification process in August 2018. (CALETC3_FF60-5)

Comment: Board Resolution 18-17 instructed Staff to work with stakeholders to develop a method for using LCFS credits from unmetered residential charging to support a state-wide EV rebate program. **NextGen strongly supports the creation of a point-of-sale EV rebate program.** It is our understanding that utilities and EV manufacturers have been conducting negotiations since the April board meeting, hoping to reach a mutually satisfactory solution. While we do not doubt all parties' shared desire to achieve this goal, or their capacity to design or implement a solution, it appears that a number of challenges remain before a mutually satisfactory agreement could be reached. (NEXTGEN3_FF65-4)

Comment: We support the CARB Board's decision to reform existing residential base credit-funded utility programs and the ongoing effort by stakeholders to create a statewide, point-of-purchase EV rebate program for California consumers. A meaningful program could dramatically spur EV adoption and reduce the CI of the state's transportation system. (TESLA2_FF69-15)

> **Agency Response:** Please refer to Response D-6.25a, General Support for a Statewide Point-of-purchase Rebate Program, in Chapter IV.

D-6.16b. *Suggestions for Statewide Point-of-Purchase Rebate Program*

Comment: Until a comprehensive, state-wide program can be developed, CARB should seek opportunities to take incremental steps toward this goal. Accordingly we suggest the following changes.

Amend § 95483 (c) (1) (A) to read:

(A) *Base Credits*. The EDU is the credit generator for base credits for EV charging at single-family residences in its service territory. The EDU must meet the requirements set forth in paragraphs 1. through 5. in section 95491 (d) (3) (A)

(1) <u>The owner or lessee of an EV may assign credits generated by residential charging of their vehicle to a third party, provided that party can provide an accurate record of residential charging on a quarterly basis.</u>

Rationale:

Allowing vehicle owners to assign residential charging credits to a third party will allow voluntary participation in a number of rebate or incentive programs, including point-of-sale rebates offered by manufacturers or financiers. With the right to assign credits clearly established in the statute, an EV buyer could sign future residential charging credits over to the EV manufacturer in return for a rebate at the time of sale. Manufacturers would, in turn, use the ongoing stream of LCFS credits to finance future rebates. This is, in fact, the basic model proposed by auto manufacturers for a state-wide point of sale rebate. Under this proposed change, auto finance companies or carbon credit aggregators could enter the market with a range of innovative products. Should an owner decline to assign credits, or if no alternatives are available, the credits would revert to the EDU by default. (NEXTGEN3_FF65-5)

Agency Response: Please see Response D-6.25d in Chapter IV.

D-6.16c. *Suggestions for Statewide Point-of-Purchase Rebate Program*

Comment: Comments on Possible Statewide Point of Sale Rebates Funded by LCFS Residential Charging Credits

We support the ongoing efforts by EV manufacturers, utilities and other stakeholders to develop a comprehensive, State-wide point-of-sale EV rebate. While we would prefer that such a rebate be administered by a state agency or independent non-profit organization, we recognize that allowing EV manufacturers to manage the program may be a simpler, but similarly effective solution, provided appropriate safeguards and oversight mechanisms exist. If EV manufacturers are to manage the program, CARB must provide rigorous oversight to ensure that the value of LCFS credits is returned to Californians. The program administrator should be compensated for reasonable management costs arising from the rebate program, but the administration of such a program should not yield profit or speculative opportunity for the administrator. This means CARB must require transparent accounting of revenues and expenditures; automakers that wish to manage their own programs must commit to promptly disbursing revenue from the sale of LCFS credits.

To this end, any organization which seeks to receive LCFS credits for the purpose of providing a point-of-sale rebate must provide a transparent proposal for administering the program for CARB and allow for public review. This must include:

- A clear indication of expected revenue and expenditure, including financing, administrative costs, risk premiums, and any other expenditure that is not returned to the public via EV rebates.
- A verifiable plan of action to increase rebate expenditure in the event that LCFS credit prices will be above plan assumptions, resulting in more revenue than anticipated.
- The capacity to track the number of LCFS credits generated by residential charging of the vehicles for which LCFS credits will be assigned to the manufacturer and excluding charging at public, private or commercial metered charging station. Credits from metered stations shall remain with the station operator, as under the current LCFS protocol.
- Regularly scheduled reviews to demonstrate that the program is actually performing in line with expectations.
- A commitment to allow an independent audit at CARB's discretion. (NEXTGEN3_FF65-7)

Agency Response: Please refer to Response D-6.25b in Chapter IV.

E. Regulated Entities

E-1. *Support for the Proposed Modifications to Regulated Entities*

Comment: In the presentation, slide 30 speaks to Electric Vehicle Charging and the Hierarchies of Credit Claims. The last bullet on the slide notes that owners of EV charging equipment (i.e. FSE) can designate any other entity to claim credits on its behalf. SRECTrade appreciates this consideration and believes that the ability for charging equipment owners to designate other entities to claim the LCFS credits on their behalf is imperative to allow some owners to participate in the market. Without the ability to designate another party to act on their behalf, they may not enter the market at all. (SREC2_FF53-3)

> **Agency Response:** Staff appreciates the commenter's support for the proposed flexibility that would enable a third-party entity to participate in the program on behalf of a credit generator for EV charging as long as it can meet all the necessary registration and reporting requirements.

E-2. *Designee as an Opt-in Entity*

Comment: While it appears that the intent of this modification is to allow third parties to act as an agent on behalf of the equipment owner, we would request some clarification in the ability of the designated-third party to register the charging equipment of a variety of different owners into one aggregated account in the LRT-CBTS. This would simply allow the third-party designee to manage multiple different owners charging equipment in one single LRT-CBTS account. It appears that the ability to facilitate this under the modified regulations is possible, but it is not clearly defined. While we do not intend to unnecessarily clarify something, we would appreciate staff's consideration on this matter. We believe that if our company or others are to provide a third-party service to charging equipment owners, it is important to clarify the possibility of this relationship in the regulations. If this is already clarified in a section of the modified regulations and we have misread or misunderstood the documents, we would appreciate you directing us to the specific language.

By way of background, included herein is a document that the PJM Environmental Information Services tracking registry utilizes to demonstrate owner's consent for a third-party to handle all registry, reporting, and credit services on their behalf (see Exhibit A: SCHEDULE A Generator Owner's Consent). We believe this may be a good example of how owners can designate third parties to act on their behalf within the CA LCFS market. (SREC2_FF53-4)

> **Agency Response:** Staff appreciates the commenter's suggestion for developing efficient registration tools; however, this is not directly within the current rulemaking scope. Instead it is an important implementation issue. Staff is committed to continue working with stakeholders in the development of efficient registration tools to allow easy registration of designee on behalf of a fuel reporting entity.

F. Average Carbon Intensity Requirements and Fuel Availability

F-1. *2030 Target should be Set to Achieve a Greater CI Decline*

Comment: We reiterate our concern that the proposed CI reduction target, 20% by 2030, is excessively conservative and likely to send an insufficient signal to fuel markets to produce the greatest possible benefits for California.[4]

[4] Please see our April 23rd comment letter and supplementary material for more detail.

(NEXTGEN3_FF65-3)

Agency Response: Please see Response F-2.2 in Chapter IV.

F-2. *Benchmark for Gasoline*

Comment: There appears to be an error in Table 1. The 2024 gasoline benchmark is listed as 87.90 gCO2e/MJ. However, the appropriate value should be:

2024 Benchmark = (1 - 0.125) * 99.46 gCO2e/MJ = 87.03 gCO2e/MJ

Where 0.125 reflects a 12.5% reduction and 99.46 gCO2e/MJ is the 2010 base year CI value for California RFG as referenced in footnote **** to Table 1. It appears that the 2024 diesel benchmark in Table 2 (87.90 gCO2e/MJ) was inadvertently also used in Table 1 for gasoline. (WSPA5_FF19-6)

Agency Response: As the commenter suggests, the diesel benchmark for 2024 was inadvertently copied into the gasoline benchmark table. In response to this comment, staff corrected the typographical error in Table 1.

G. Credit and Deficit Provisions

G-1. Multiple Comments: *Support for the Proposed Credit and Deficit Provisions*

Comment: We appreciate ARB adding language to clarify in additional text in section 95487(a)(2)(B) does not prohibit the contracting for future delivery of LCFS credits. The ability to trade future credits will provide market stability to credit trading. (CRF2_FF42-3)

Comment: REG supports the updated and clarified language under credit transfers in 95487(b). (REG3_FF44-18)

Comment: 4. CalETC supports the 15-day modification language that specifies that deficit generators "may not borrow or use credit from anticipated future carbon intensity reductions", but credit generators may do so.[17]

[17] See section 95487(a)(2)(B) on page 37 of the 15-day modifications.

(CALETC3_FF60-16)

> **Agency Response:** Staff appreciates the commenters' support for the proposed changes related to the LCFS credit trading and reporting the credit transfers in the LCFS Reporting Tool and Credit Banking System (LRT-CBTS).
>
> In response to CALETC3_FF60-16, staff would like to clarify that regulated entities in the LCFS may not "borrow" or use anticipated future carbon intensity reductions to demonstrate compliance pursuant to section 95485(a). However, this does not preclude contracting for future delivery of LCFS credits as described in section 95487(b)(1)(B).

G-2. *Reporting Credit Transfers*

G-2.1. Multiple Comments: *Time Limit to Cancel or Reverse a Trade*

Comment: Section 95487(d)(7) – Prohibited Transactions was added to the regulation to clarify CARB's authority to cancel or reverse any trade deemed to have violated subsections (1) – (6). This new remedy should have a time limit associated with it. As written, it would extend indefinitely. Entities need to be able to close their books after compliance has been determined. **RPMG recommends the following language and formatting changes** (this language should not be part of the list of prohibited transactions).

> ~~(7)~~ Upon investigation pursuant to section 95495, the Executive Officer may cancel or reverse a credit transfer <u>within 180-days of annual verification</u> if a credit transfer is determined to be a prohibited transaction as per subsection (1) through (6) above. The Executive Officer shall notify the parties and identify the reasons for cancelling or reversing a credit transfer. (RPMG3_FF41-3)

Comment: GlassPoint would like to note a concern that there is not a temporal limitation on the new sub-section 95487(d)(7) under Prohibited Transactions. This new authority spelled out to prevent transactions needs to be limited to a timeframe concurrent to the actual transaction. Commercial transaction cannot be subject to indefinite invalidation. GlassPoint recommends 180 days. Additionally, the language in sub-section (7) should not be part of the list of prohibited transactions, (as it is not a prohibited transaction itself) but rather a concluding paragraph to that section. (GLASSPOINT2_FF54-6)

> **Agency Response:** Staff would like to clarify that the Executive Officer may cancel or reverse a credit transfer only if the credit transfer is determined to be a prohibited transaction upon completion of the investigation process pursuant to section 95495. If a credit transfer is discovered, upon investigation, to be a prohibited transaction (even after the commenters' recommended 180 days) CARB must have the authority to take necessary action to minimize any impact on the credit market from any such transaction. Therefore, there is no explicit time limit on the authority to reverse or cancel a prohibited credit transaction.

G-2.2. ***Proposed Amendments for Reporting Credit Transfers***

Comment: Section 95487(b)(1)(D) needs to be modified to reflect the expected complexities associated with credit transaction contracts related to multi-year offtake agreements associated with LCFS Credit based financing of large capital project. As we have discussed, the request for information about the terms remains vague and could present implementation issues. GlassPoint suggests that language be added that allows for these more complicated transactions to easily be reported to CARB. We suggest the language below. (Note the punctuation changes as well on #4 and #7.)

(D) *For Type 2 Transfer.* Within 10 days from the date the parties enter into the credit transaction agreement, the Seller and the Buyer must report the following using the Credit Transfer Form (CTF) provided in the LRT-CBTS:

1. *Date of Transaction Agreement.* The date on which the Buyer and Seller enter into the credit transaction agreement;

2. Names and the Federal Employer Identification Numbers (FEIN) of the Seller and the Buyer as registered in the LRT-CBTS;

3. First name, last name, and contact information of the Seller and Buyer representative;

4. If the agreement requires a single delivery of credits or multiple delivery of credits;

5. The expected date of last credit delivery or the expected length of the agreement including the date by which all deliveries are to be completed;

6. ~~The~~ An estimate of total number of credits anticipated to be transferred under the agreement;

7. The price per credit (in U.S. dollars) or a summary of the terms to determine the price for future credit transfer as per the agreement~~.~~;

8. If the agreement is terminated or amended prior to its full execution as provided in subsection 5. above, the parties must notify the CARB within ~~10~~ 30 business days. (GLASSPOINT2_FF54-8)

   Agency Response: Staff appreciates the commenter's suggestion and the final text requires reporting of the "expected" date of the last credit delivery in section 95487(b)(D) as proposed by the commenter. Staff believes the other recommended changes provided in the commenter, though thoughtful, are repetitive or unnecessary.

H. Buffer Account

H-1. *Suggestion for the Proposed Buffer Account*

Comment: Finally, CARB staff could also consider using LCFS credits from the buffer account for this program either in place of capacity payments or in combination with capacity payments. Along these lines, the buffer account would have 3 separate buckets split evenly. Bucket 1 would be credits to cover invalidated LCFS credits (e.g. CCS). Bucket 2 would be bucket just for the FCI and HRI programs. Bucket 3 would be for infrastructure projects for that fuel type. For instance, if a biodiesel plant had 99 LCFS credits going to the buffer account, then the 33 credits for bucket 3 would go to a biodiesel specific infrastructure project. (REG3_FF44-16)

> **Agency Response:** Staff appreciates the commenter's suggestion but would like to note that the buffer account is designed to help mitigate the invalidation risk for credit buyers and safeguard the environmental integrity of the program in case of credit invalidation. The proposal in the comment may render it ineffective for the intended purpose in some cases and, therefore, this suggestion was not implemented.

H-2. *Concerns about the Proposed Credit Contribution into the Buffer Account*

Comment: Also, as suggested above, REG believes the combination of a buffer account and a conservative CI would mitigate concerns with a higher operational CI than the certified CI. (REG3_FF44-27)

> **Agency Response:** Please see Response H-3, Concerns about the Proposed Credit Contribution into the Buffer Account, in Chapter IV.

I. Infrastructure Crediting

I-1. Multiple Comments: *Support for Proposed Infrastructure Crediting Provisions*

Comment: Proterra supports the proposed inclusion of section 95486.2, which would credit zero-emission fueling infrastructure based on station capacity, for both hydrogen refueling infrastructure (HRI) and DC fast charging infrastructure (FCI). This additional pathway will help incentivize deployment of zero-emission infrastructure, helping to implement the Governor's Executive Order B-48-18. (PROTERRA2_FF3-2)

Comment: PG&E recognizes the need for publicly accessible zero-emission vehicle infrastructure, and the challenges associated with making investments in alternative fuel stations at this early phase of the market. Increasing the number of DC fast chargers and hydrogen (H2) stations will help accelerate the market for both fuel cell and battery-electric technologies, and make refueling more accessible to California residents who do not currently have access to home charging or a nearby hydrogen station.

ARB Staff's proposal for capacity crediting programs for DC fast chargers and H2 stations is an innovative approach to incentivize additional clean transportation infrastructure. (PGE2_FF64-2)

Comment: Air Products is pleased that industry stakeholders continue to develop innovative proposals to accelerate the development and build out of hydrogen refueling stations in California. We understand the proposal for Hydrogen Refueling Infrastructure (HRI) Crediting to generate LCFS credits based on hydrogen fueling capacity under the LCFS can possibly accelerate the expansion of hydrogen fueling stations; (AP1_FF16-1)

Comment: We support the *Hydrogen Refueling Infrastructure* (HRI) Pathway as proposed by the California Air Resources Board (ARB) in the 15-day Notice of Public Availability of Modified Text and Availability of Additional Documents and Information for Proposed Amendments to the Low Carbon Fuel Standard (LCFS) Regulation and to the Regulation on Commercialization of Alternative Diesel Fuels (ADF) (henceforth "15-day Notice"). In the second part of this letter, we also propose amendments to strengthen the proposed regulation. (H2IND2_FF17-1)

Comment: We believe the HRI can provide an effective incentive for expanding zero-emission vehicle infrastructure while remaining consistent with the LCFS policy's intent, by accomplishing the following during the early years of Fuel Cell Electric Vehicle (FCEV) deployment:

- partially offset the initial lower utilization of hydrogen refueling stations, thereby supporting refueling network development to increase the availability of hydrogen fuel;
- enable efficient development of hydrogen refueling stations at a sustained pace and scale to achieve significant cost reduction, promoting the efficient use of

public and private funds and reducing the cost of low-carbon fuels for Californians;

- enable the incentive structure already in place in the LCFS to reduce the carbon intensity of hydrogen through increasing renewable content;
- become self-balancing and sun-setting, with credit generation through the HRI decreasing overtime as hydrogen sales and station utilization increase;
- ensure best-in-class carbon intensity and infrastructure quality through eligibility conditions;
- ensure no material or unintended impacts to the overall LCFS policy and stakeholders through fixed limits on duration, infrastructure capacity, and credit generation. (H2IND2_FF17-2)

Comment: In closing, we believe the HRI can be effective for accelerating the build out of hydrogen refueling stations and reducing the carbon intensity of hydrogen supply, consistent with Executive Order B-48-18 and Board Resolution 18-17, and the LCFS policy intent. (H2IND2_FF17-12)

Comment: 3. Hydrogen Refueling Infrastructure (HRI) Pathway: The proposed changes would assign, with certain restrictions and requirements, LCFS credits for hydrogen refueling based on the capacity of the hydrogen refueling station. ***We support this change.***

Despite the best efforts and intentions by the automakers, Energy Commission, ARB, Governor's office, and legislature, hydrogen refueling station deployment has progressed far slower than expected, with only 35 retail stations currently open in California. This delay in retail fueling stations has slowed deployment of FCEVs. Providing LCFS credits based on the capacity of a station could provide a substantial incentive for the fueling providers and significantly accelerate the hydrogen fueling infrastructure toward the goals established in Governor Brown's Executive Order S-01-07. (AAMGA1_FF18-4)

Comment: Shell specifically would like to express our support for two elements of this program, which cover … a provision to accelerate development of hydrogen fueling infrastructure that ultimately will play a major role in the State's ongoing quest to reduce its greenhouse gas (GHG) emissions.

…

The Hydrogen Refueling Infrastructure (HRI) Pathway is an important step to help the State meet Governor Brown's formidable goal of the deployment of five million electric vehicles (EVs) in California by 2030, per Executive Order B-48-18. The HRI Pathway proposed in the 15-Day Package will enable the near-term buildout of a critical mass of hydrogen fueling stations to support Executive Order B-48-18. Californians who must travel longer distances, have limited access to charging at home or work, or prefer refueling over recharging would be well served by fuel cell electric vehicles (FCEVs).

Hydrogen also holds significant promise for fueling heavy-duty vehicles. This an important differentiator from other EV platforms, and the ARB is prudent to provide support to FCEVs via the HRI Pathway given these practicalities.

The HRI Pathway has benefitted from eight months of public input and is consistent with Executive Order B-48-18 and LCFS policy intent. The proposed pathway is appropriately constrained to hydrogen fuel, and the unique aspects thereof, and in size and duration and with eligibility requirements to protect against unintended adverse consequences, while nonetheless supporting the low-carbon, clean-air, and EV goals of the State of California. (SHELL2_FF57-2)

Comment: The Low Carbon Fuel Standard (LCFS) is one such program that has been pivotal in stimulating investment in ZEV infrastructure, and EVgo applauds CARB for its leadership in taking LCFS one step further by proposing DC Fast Charging Infrastructure (FCI) Credits which will accelerate realization of the 10,000 DCFCs by 2025 goal envisioned by Governor Brown in his Executive Order.

…

Programs like LCFS are critical to meeting the goals laid out by the Governor in his Executive Order, calling for five million ZEVs in California by 2030 and 250,000 electric vehicle chargers, including 10,000 direct current fast chargers, by 2025. (EVGO1_FF62-1)

Comment: On behalf of FirstElement Fuel, I am writing to express support for the *Hydrogen Refueling Infrastructure* (HRI) Pathway as proposed by the California Air Resources Board (ARB) in the 15-day Notice of Public Availability of Modified Text and Availability of Additional Documents and Information for Proposed Amendments to the Low Carbon Fuel Standard (LCFS) Regulation and to the Regulation on Commercialization of Alternative Diesel Fuels (ADF) (henceforth "15-day Notice"). The program is well thought-out, and provides a mechanism that will help boost the successful deployment of retail hydrogen stations while also helping to achieve the following critical goals:

- Accelerate build-out of the retail hydrogen network in California
- Entice more private money to invest in hydrogen infrastructure
- Hasten the transition away from grant funding for hydrogen stations
- Help reduce price at the pump
- Incentivize higher percentage of renewable hydrogen (FEF1_FF71-2)

Comment: I also want to let you know that although we signed onto the letter by other Hydrogen Stakeholders for the sake of unity, FirstElement believes that the reporting and record keeping requirements that the CARB is contemplating as part of the HRI program are appropriate and feasible from our perspective. In other words, we do not share the view of the other stakeholders on this point. (FEF1_FF71-1)

Comment: We strongly support the requirement contained within the HRI proposal to not provide capacity credits to hydrogen stations that show no record of fueling. This will discourage the construction of stranded stations. We strongly encourage CARB to consider this requirement for FCI as well. This is appropriate give that the capital required to build a station is less than a hydrogen station, there are far more electric vehicles on the road, and those vehicles are being added to state vehicle pool at a much more rapid rate. (REG3_FF44-14)

Comment: To align with the Governor's Executive Order B-48-18 of 10,000 direct current fast chargers (DCFC) by 2025, the City of Los Angeles' contribution will be approximately ten percent of that goal at 1,000 DCFC. LADWP supports ARB's concept for infrastructure crediting for the purpose of incentivizing early-stage infrastructure buildout. (LADWP2_FF10-6)

Comment: 4. DC Fast Charging Infrastructure (FCI) Credits: Our associations support efforts to help build a robust network of public direct current fast chargers (DCFCs) in the state of California. DCFCs – along highway corridors, near destinations, and to support transportation network companies – enable faster recharging where needed and longer distance travel. Fast charging is increasingly necessary as more long-range vehicles enter the market, and customers see greater opportunities to completely replace internal combustion engines with electric vehicles in travels throughout the state. However, DCFCs are more expensive to install and operate, and a robust business model has yet to be identified. Therefore, we support FCI credits, understanding that such credits should incentivize and accelerate the installation of DCFC, provide more fast charging options for Californians, and ultimately support more PEVs on the roadways. (AAMGA1_FF18-6)

Comment: *SMUD supports the concept of allowing a DC Fast Charging Infrastructure pathway now described in proposed section 95486.2.*

SMUD supports CARB's recommended eligibility requirements as follows.

Subsection (b)(1)(B): SMUD supports the proposal to require sites to support at least two of the three currently used DC Fast Charging (DCFC) connector types, along with a requirement for one third of units at a site to be able to support multiple connector types. We believe that this is a good compromise in meeting equity goals and promoting the deployment of infrastructure that can be used by all EV drivers in California.

Subsection (b)(4)(C): SMUD supports the requirement for using public point of sale methods that accept credit cards or debit cards. SMUD has deployed six DC Fast Charging stations in the Sacramento area dating back to 2014 equipped with credit/debit card readers and believes that they are an important feature to help drive EV adoption by informing the public of similarities between EV charging and regular fossil fuel dispensary operations. (SMUD2_FF63-6)

Comment: We support the inclusion of DCFC technology in capacity crediting, which the Board directed staff to explore at the April 2018 hearing. The FCI pathway, if

designed and implemented effectively, has the potential to significantly accelerate the deployment of DCFC infrastructure in the state in accordance with the Governor's goal of 10,000 chargers by 2025 to support widespread EV adoption in the state.

With Tesla's U.S. vehicle sales already representing a majority of today's DCFC-capable market,[1] Tesla supports initiatives that help offset the cost of DCFC infrastructure deployment to serve growing consumer demand. We have invested significant resources in the Supercharger network, which is designed to enable long-distance travel and remove a barrier to the broader adoption of EVs caused by the perception of limited vehicle range. Supercharger sites typically have between six and twenty chargers and are strategically placed along well-travelled routes. We are also building stations in an increasing number of city centers to enable urban use. The Supercharger network will never be a profit center for Tesla and the cost to consumers, if any, will always remain significantly cheaper than gasoline.

[1] IHS/Polk data.

(TESLA2_FF69-12)

Comment: FirstElement Fuel generally agrees with the analysis capability and methodology employed by NREL's H2FAST tool, and we also agree that the ARB's desired outcome (returns on investment in the low teens) represent a significant benefit to our business model and will help attract private investment, without being excessively lucrative. (FEF1_FF71-4)

> **Agency Response:** Staff appreciates the general support for the proposed inclusion of section 95486.2, as well as support by individual stakeholders for specific provisions.

I-2. ***Public Fleets***

I-2.1. Comment: 1. Proterra respectfully requests expanding eligibility for zero-emission fueling based on station capacity for public fleets to help further spur zero-emission, battery-electric medium and heavy-duty DC fast charging infrastructure. This will help support the California Air Resources Board's efforts to accelerate the deployment of zero-emission public transit buses with the Innovative Clean Transit initiative, as well as zero-emission school buses and other medium- and heavy-duty zero-emission vehicle technologies for public fleets. (PROTERRA2_FF3-3)

> **Agency Response:** The ZEV Infrastructure crediting provisions were designed with the intent of supporting the targets established by the Governor in Executive Order B-48-18, including rollout of 5 million ZEVs by 2030 and buildout of 10,000 DC fast chargers by 2025. While not excluding the heavy-duty sector, the Executive Order focuses on light-duty vehicle deployment and the associated charging infrastructure necessary to support the desired increase in ZEV deployment. Placing an early emphasis on infrastructure buildout helps to eliminate the "chicken or the egg" relationship where individual consumers will not adopt the vehicles without sufficient infrastructure. Accordingly, staff has designed the provision to incentivize the buildout of fast chargers for the

light-duty sector, as evidenced by use of the light-duty vehicle EER value and gasoline benchmarks in the FCI credit generation equation.

Staff believe the “chicken-and-egg” problem is less severe on the heavy-duty fleet side where charging infrastructure and vehicle purchases can often be better matched under the control of the same actor. Therefore, the proposed crediting method is not well-suited to chargers designed for fleets of heavy-duty vehicles. For example, under the final language, DC fast chargers owned by public fleets would need to meet public accessibility and payment methods requirements listed in section 95486.2(b).

I-2.2. Comment: 2. With the inclusion of public fleets, we recommend removing the requirement to support at least two of the qualifying commercial fast charging connectors. For public fleets, such as transit agencies or school districts, this requirement is not needed, as most fleets use a single technology and charging infrastructure, and additional connectors would be underutilized. In addition, we fully expect similar situations to arise in the light and medium duty sector so multiple connector deployment could limit charging capability for fleets and potentially the general public. (PROTERRA2_FF3-4)

Agency Response: Please see Response I-2.1 in this chapter regarding eligibility of public fleets to receive FCI credits. In response to stakeholder feedback, staff modified the initial proposition that all FSE must be capable of supporting at least two different fast charging connector protocols and must have at least one FSE each supporting the SAE CCS connector and at least one supporting the CHAdeMO connector. The final language includes a limit applicable only for the applications that are submitted after an applicant’s estimated potential FCI credits exceed 0.5 percent of total program deficits in the prior quarter. Staff also proposed that no more than 3/4, rather than 1/2, of FSE at a given site could follow only one connector protocol. Staff believes that these changes provides a greater degree of initial flexibility for the market to drive optimal connector protocol ratios, while maintaining equity in the program by requiring that a diverse set of connector types be installed. Staff disagrees with the commenter’s assertion that mandating inclusion of multiple connector types at a given site would limit charging capability for the general public, for whom this provision was designed.

I-3. *Not in Support of the Proposed Infrastructure Crediting Provisions*

I-3.1 Multiple Comments: *Departure from Fuel Neutral Approach and would not Represent Actual GHG Emission Reductions*

Comment: We are deeply disappointed that the latest regulatory amendments propose allowing the building of hydrogen and EV charging infrastructure to generate credits within the LCFS program – beyond crediting of the actual supplying of fuel for transportation. As no other fuels within the LCFS program would be able to generate credits in this way we, and many other stakeholders, view this as a clear and

unprecedented departure from a fuel neutral approach. Moreover, the proposal, if adopted, would seriously undermine the environmental integrity of the program by offering credits for activities for which no actual carbon intensity reductions occur.

The LCFS was designed, adopted, and has been heavily promoted as a market-based, fuel neutral program. While many other programs have been designed to subsidize and incentivize specific fuels – the LCFS has been promoted as a program that allows all fuels to compete on a level playing field – based only on their carbon intensity. Developers of alternative fuels of all kinds have invested based on a belief that their product could compete within the LCFS on a level playing field with other fuels, based solely on the carbon intensity of the fuels they produce. Now these alternative fuel investors must compete and invest with the knowledge that CARB sees the LCFS as just another program where a thumb on the scale will be used to advantage specific, chosen fuels.

Together, we have worked very hard, across multiple programs which comprise California's GHG reduction efforts, to ensure that all GHG reductions are real, quantifiable, verifiable and permanent. From the very detailed requirements on offset projects, to the rigor of pathway demonstration for biofuels crediting in the LCFS, to the verification of GHG emissions, and more – ensuring and maintaining environmental integrity is a bedrock principle to which an effective GHG reduction program must adhere. We believe very strongly that the LCFS must continue to adhere to this principle and that credits can only be awarded for activities that produce real, quantifiable, verifiable and permanent GHG reductions – using a fuel neutral approach.

The production of hydrogen and electricity for transport fuel will already receive LCFS credits under the current program – currently equivalent to a subsidy in the amount of approximately $180 per ton of carbon. In addition, developers of hydrogen and EV charging infrastructure collectively receive tens of millions of dollars annually in grants from the California Energy Commission and from other sources. The current LCFS proposal to also give credits for the activity of building infrastructure (in addition to credits for producing fuel) suggests that these current incentives are not enough. This begs the questions – how much is enough – and how much is too much?

Given the departures from fuel neutrality and environmental integrity that adoption of these proposals would represent, and the uncertainty that this introduces for producers of other fuels, we believe that CARB should pause – and consider whether the desire to pick winners within the LCFS is strong enough to sacrifice the very credibility of the program – or whether there are other methods and other programs that can be more appropriately be used to further subsidize favored outcomes. (BP2_FF8-1)

Comment: § 95486.2. Generating and Calculating Credits for ZEV Fueling Infrastructure Pathways

WSPA regrettably cannot support these proposed pathways as they do not adhere to our long-held principles for fuel neutrality and emissions integrity in California's suite of climate policies. (WSPA5_FF19-5)

Comment: Valero is concerned that the proposed amendments to the LCFS program run counter to the purpose of the program and the underlying statute. The Agency's proposal undermines the fuel neutrality of the LCFS program and creates a technology forcing regulation which favors ZEV fueling alternatives over liquid fuels. Furthermore, the proposal allows for the generation of credits with no measurable emission reductions.

ARB has taken the position that the Governor's Executive Order B-48-18 and Board Resolution 18-17 grant them authority to incentivize ZEV infrastructure construction through the LCFS program. Valero contends that the executive order which requires, "all State entities work with the private sector and all appropriate levels of government to spur the construction and installation of 200 hydrogen fueling stations and 250,000 zero-emission vehicle chargers, including 10,000 direct current fast charges, by 2025" can be achieved through development of other regulation or incentive programs without jeopardizing the integrity and intent of the LCFS program. Thus, mitigating the need to generate capacity based credits through the LCFS program to incentivize ZEV infrastructure growth and abiding by the statue.

ARB stated during the June 11th workshop the Board directed them to move forward with capacity credits for ZEV infrastructure while retaining the 20% target carbon intensity reduction over the life of the program. Thus, capacity credits can be utilized by regulated parties to demonstrate compliance; however, capacity credits will be excluded from calculating the carbon intensity of the fuel mix at the end of a compliance period. There is no safeguard or alternative for regulated parties if the carbon intensity of the actual fuel mix exceeds the carbon intensity benchmark for a given compliance period. There is no defined recourse of how the gap will be reconciled amongst regulated parties who have complied with the regulation by purchasing credits which may include capacity credits. Thus, leaving regulated parties at risk of having to purchase additional credits to comply with the benchmark carbon intensity. (VALERO3_FF27-1)

Comment: 1. The proposed crediting mechanism for DC fast charging and hydrogen refueling infrastructure threatens to undermine the performance-based, technology-neutral design of the LCFS

CARB is proposing to add section 95486.2 to the LCFS regulation, establishing a mechanism that would allow the generation of LCFS credits for the installation of "zero-emissions vehicle" (ZEV) refueling infrastructure. Specifically, the provisions would allow owners of hydrogen refueling equipment and DC fast charging infrastructure to generate LCFS credits simply for installing the equipment.

These proposed provisions threaten to subvert the original spirit and intent of the LCFS, which was to focus on decarbonization of transportation fuels (as opposed to providing direct incentives for low-carbon fuel infrastructure) and to "…offer a ***fuel-neutral platform*** in which alternative fuels can be incentivized ***without choosing winners or losers***."[2]

[2] California Air Resources Board. March 5, 2009. "Proposed Regulation to Implement the Low Carbon Fuel Standard, Volume I, Staff Report: Initial Statement of Reasons," at V-2. (emphasis added) https://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor1.pdf

Hydrogen and electricity are only two of many low-carbon alternative fuels used in California under the LCFS. Ethanol, biodiesel, renewable diesel, biogas, and several other alternative fuels have made valuable contributions toward achieving the goals of the LCFS. Allowing only hydrogen and DC fast charging infrastructure to qualify for credit generation clearly violates the LCFS program's intended "fuel-neutral platform" and absolutely results in "choosing winners [and] losers."

The LCFS has been promoted worldwide as a policy model that is equitable, nonprescriptive, and drives decarbonization by valuing fuels *strictly on carbon intensity performance*. Indeed, CARB has stated that, "The design of the regulation ***is performance-based*** to ensure that all fuels that contribute to the goals of the LCFS are ***treated equitably***."[3] For the most part, the LCFS has operated effectively under these principles. However, the proposed crediting mechanism for hydrogen refueling and DC fast charging equipment would destabilize the performance-based design of the program and treat alternative fuels inequitably. At a time when other jurisdictions are considering programs patterned after the LCFS, these proposed provisions threaten to sully the reputation of the California program as a truly performance-based, technology-neutral policy.

[3] Id., at ES-32. (emphasis added)

a. Credits generated for ZEV infrastructure would not represent actual carbon reductions and may result in double-counting

When the LCFS was originally designed, it was clearly established that credits would serve as the currency of the program, with each credit representing one metric ton (MT) of CO_2-equivalent (CO2e) reduction below the annual standard. The simple elegance and transparency of the LCFS credit instrument (i.e., one credit equals one MT of CO_2e) has enabled broad participation in, and effective operation of, the credit market. In addition to facilitating creation of the nation's first true market for monetized carbon, the LCFS credit mechanism has served as a practical and straightforward metric for measuring carbon reductions achieved under the program.

Unfortunately, allowing generation of credits for ZEV infrastructure installation would jeopardize the integrity of the LCFS credit market and greatly complicate the accounting of actual carbon reductions achieved under the LCFS. This fact has been acknowledged by CARB officials, one of whom stated, "We acknowledge that these credits do not represent actual greenhouse gas emissions reductions."[4]

[4] J. Godwin. June 25, 2018. "CARB Seeking Feedback in 15-Day Comment Period for LCFS Proposals." Oil Price Information Service. Biofuels Update.

While this same official suggested that CARB "will remove those credits" when "making claims about the reductions the program has accomplished,"[5] the ZEV infrastructure credits will be indistinguishable from credits that actually represent GHG reductions when transacted in the marketplace. In other words, the LCFS credit market may become diluted with credits that don't actually represent real GHG reductions. ZEV infrastructure credits will have the same influence on the overall supply, demand, and

pricing of LCFS credits as credits derived from actual GHG reductions, but they will not be providing any real service to the environment.

[5] Id.

Further, allowing credits to be generated for ZEV infrastructure installation likely would result in "double-counting" when that infrastructure is used to actually dispense or distribute the fuel. That is, credits would be generated for both the *capacity* to distribute the fuel as well as for the actual distribution and use of fuel in the vehicle. (RFA3_FF30-1)

Comment: Since its inception, the LCFS (Low Carbon Fuel Standard) has been promoted as a fuel-neutral regulatory structure that credits and debits real transportation fuels used in the marketplace to generate emission reductions. However, the 15-day package proposes mechanisms to generate LCFS credits for installation of Fast Charging Infrastructure (FCI) and Hydrogen Fueling Infrastructure (HFI), independent of fuel sales. These provisions are contrary to CARB's description of the program:

> "The LCFS is performance-based and fuel-neutral, allowing the market to determine how the carbon intensity of California's transportation fuels will be reduced."

CIPA suggests that the pillar of fuel neutrality importantly provides for the most cost-effective reductions in the marketplace to avoid distortions that can undermine real-world progress in reducing the carbon intensity of transportation fuels.

As such, CIPA requests that the provisions for FCI and HFI be removed from the LCFS regulation. (CIPA2_FF43-1)

Comment: Clean Energy opposes the proposal to implement LCFS crediting for hydrogen and DC fast charging fueling infrastructure. Since inception, the intent of the LCFS program has been to reduce emissions of greenhouse gases (GHG) by lowering the carbon intensity of transportation fuels in California. The program set an initial goal of a 10% realized reduction in California's fuel carbon intensity by 2020 with a proposal to increase to a 20% reduction by 2030. According to the 2009 Initial Statement of Reasons:

> *"The LCFS framework is based on the premise that each fuel has a "lifecycle" GHG emission value that is then compared to a standard. This lifecycle analysis represents the GHG emissions associated with the production, transportation,* ***and use of low carbon fuels in motor vehicles.****"*

The foundation of the LCFS program has always been based around a lifecycle emissions standard for fuel (not infrastructure) which promotes two key elements of the LCFS program:

1. Real quantifiable GHG reductions of California transportation fuel;
2. Fuel Neutrality.

Implementing provisions to allow LCFS crediting for hydrogen and DC fast charging fueling infrastructure is a significant departure from the established lifecycle emissions standard and violates the founding principles of the LCFS program altogether. LCFS credit generation from station fueling capacity does not represent real quantifiable GHG reductions of California transportation fuel. An LCFS credit represents one metric ton of GHG emission reduction achieved from a specified volume of fuel **delivered and consumed** in California. An LCFS credit generated based on fueling capacity is not real and could be non-existent if a corresponding volume of that fuel is not delivered and consumed in the state.

Furthermore, if staff was to implement a concept of capacity crediting then it should apply to all low carbon fueling infrastructure in California and not limited to hydrogen and DC fast charging. The LCFS set forth a path to reduce the carbon intensity of California transportation fuel through a diversified supply of any low carbon fuels through the lifecycle emissions model. This performance based mechanism drives low carbon fuel innovation as evidenced by the declining (and even negative) carbon intensity of fuels in the program today. We believe ARB must adhere to these principles and uphold the performance standard established in the LCFS program to date. Fueling infrastructure that can achieve significantly low and even negative carbon intensity, such as biomethane, should be incentivized just as much as hydrogen or EV fueling infrastructure. Therefore, either all low carbon fuels should be able to generate credits based on capacity or there should not be any crediting for capacity.

The concept of crediting for capacity is also counter-intuitive with staff's proposal for annual carbon intensity (CI) verification and the concept of a "margin of safety" for all biofuel pathway CI scores. As proposed, biofuel producers will only be able to realize environmental value for LCFS credits representing actual verified reductions in GHG emissions. Generation of any excess LCFS credits above actual verifiable GHG reductions is deemed a violation of the LCFS Regulation and will leave the credit generator subject to enforcement penalties.

Furthermore, Section 95488.4 of the LCFS amendments suggest that biofuel pathway applicants should add a conservative margin of safety to increase a certified pathway CI to protect against variability in operations and avoid the risk of non-compliance through potential over-generation of credits. As proposed, biofuels would only be able to realize LCFS credits for real verifiable GHG emission reductions while hydrogen and DC fast charging station owners can realize LCFS credits for potential (non-guaranteed and potentially non-existent) GHG reductions. (CE4_FF52-5)

Comment: GlassPoint has concerns that the proposed inclusion of credits associated with ZEV fueling infrastructure. Because such credits would not correspond directly to avoided CO2 emissions, they do not match the performance-based, fuel-neutral nature of all other LCFS credits. GlassPoint requests that these provisions be removed from the regulation. (GLASSPOINT2_FF54-5)

Comment: Growth Energy is also concerned that the Proposed Modifications seek to treat hydrogen and electricity differently than other lower CI alternative fuels, and

strongly suggests that CARB take a different approach that would achieve real and quantifiable greenhouse gas emissions. As such, Part II, Section A of these comments explains that, to the extent CARB issues credits for electricity and hydrogen capacity, CARB should also provide credits for capacity generated for other lower CI alternative fuels. (GROWTHENERGY2_FF56-3)

Comment: In the event CARB considers the Proposed Modifications, CARB should expand capacity credits to all low carbon fuels. (GROWTHENERGY2_FF56-56)

> **Agency Response:** Staff believes that the proposed approach to crediting ZEV infrastructure is an effective policy lever to meet State goals for ZEV deployment. The proposed Infrastructure Crediting Provisions in section 95486.2 are responsive to the targets and direction in Governor Brown's Executive Order B-48-18, California's 2017 Climate Change Scoping Plan, CARB's 2016 Mobile Source Strategy, and to explicit direction from the CARB Board after extensive input from stakeholders who proposed the concept early in this rulemaking (see Resolution 18-17) and consistent with CARB's authority pursuant to AB 32.
>
> Staff acknowledges that these provisions constitute a limited departure from fuel neutrality, and underscores the importance of a diverse portfolio of low-carbon fuels in order to meet CI reduction goals under the program. However, as outlined in the material supporting CARB's Advanced Clean Cars regulations, ZEVs are critical for addressing California's conventional air pollution and GHG goals. CARB has long recognized this and provided explicitly stronger support for ZEVs through a variety of vehicle programs.
>
> The stronger support for ZEV infrastructure reflected in these amendments better aligns the state's low carbon fuel and vehicle policies, helps reduce a barrier to ZEV adoption and is designed to help reach the Governor's goal of 5 million ZEVs on the road by 2030.
>
> With respect to specific concerns raised in the comments above, provisions within section 95486.2 set effective limits on the scope of hydrogen and DC fast charging infrastructure crediting by limiting total credits to 2.5 percent (for each category, 5 percent total) of overall program deficits. Therefore, incorporation of infrastructure crediting is expected to only marginally change incentives in the rest of the LCFS credit market relative to staff's initial proposal.
>
> Staff agrees that care must be taken to avoid reporting infrastructure credits benefits in the same way that credits for other low carbon fuels are reported, especially with respect to claims of GHG reductions. Although staff expects that expansion of ZEV infrastructure will result in increased ZEV penetration and therefore, enable future emissions reductions, staff did not attempt to quantify these second-order benefits in this rulemaking. In fact, staff explicitly removed all infrastructure credits when determining and publically expressing overall program GHG benefits from this package of LCFS amendments (please see staff's finalized updated scenarios and analyses). Staff will continue to make this

adjustment when reporting the program benefits moving forward. Moreover, LCFS credits do not factor in to the Greenhouse Gas Emissions Inventory used to evaluate California's overall progress in achieving the GHG reduction goals of AB 32 and SB 32.

Crediting of both ZEV infrastructure and actual fuel distributed is not double-counting, as one commenter suggests, as the credits are generated for separate purposes and do not overlap. Please see also Response I-3.3 in this chapter for a description of how the attributional analysis of program benefits will not impact stakeholder compliance status.

I-3.2. *Inclusion of Provisions were not Properly Noticed*

Comment: As noted above, the potential magnitude of the value of capacity credits could be on the order of tens of millions of dollars per year. Despite this, there is no evidence in the 15-Day Notice justifying the need for creating LCFS credits that provide no reductions in GHG emissions for incentivizing construction of hydrogen and DC fast charging stations. The failure to justify the need for capacity credits is particularly disconcerting in light of the fact that the California Energy Commission (CEC) has spent, and continues to spend, millions of dollars to subsidize hydrogen station construction[4] as well as the deployment of DC fast charging stations and other electric vehicle infrastructure.[5] Given this, the appropriate mechanism for increasing the number of hydrogen and DC fast charging stations is to continue to provide grant funding through the CEC's ARFVT program[6] not paying owners of hydrogen and DC fast charging stations through the issuance of LCFS credits that provide no verifiable reductions in GHG emissions. However, in the event that CARB does provide capacity credits, then the agency should provide similar "capacity" credits for all types of low CI biofuel infrastructure including E85 refueling facilities.

[4] See http://www.energy.ca.gov/2017publications/CEC-600-2017-011/CEC-600-2017-011.pdf
[5] See http://www.energy.ca.gov/transportation/tour/ev_infrastructure/
[6] See http://www.energy.ca.gov/altfuels/

(GROWTHENERGY2_FF56-66b)

Agency Response: Staff disagrees that the rationale for the proposed inclusion of the infrastructure crediting provisions was not properly noticed. In the June 20, 2018 Notice of Public Availability of Modified Text, staff demonstrated (in section H of the Summary of Proposed Modifications) the justification for exploring ZEV infrastructure crediting, including the Governor's Executive Order B-48-18, which specifically named the LCFS as an instrument to implement the proposed targets, and Board Resolution 18-17, which followed and reflected Board discussion on the issue and directed staff to develop potential crediting for ZEV infrastructure within the program. CEC grant funding has proven an effective lever, but availability of funding in future years is uncertain and is, therefore, an insufficient instrument for meeting the Governor's goals of 200 hydrogen stations and 10,000 DC Fast Chargers by 2025. Please see Response I-3.1, Departure from Fuel Neutral Approach and would not Represent

Actual GHG Emission Reductions, in this chapter and Response I-3.5 in this chapter regarding crediting infrastructure for other fuels.

I-3.3. *Credit Generation for ZEV Infrastructure*

Comment: Valero is concerned that the proposed amendments to the LCFS program to authorize capacity credits for ZEV infrastructure run counter to the purpose of the program by allowing for the generation of credits with no measurable emission reductions. Further, the proposed amendments may leave regulated parties at risk of having to purchase additional credits if the carbon intensity of the actual fuel mix for a given compliance period exceeds the carbon intensity benchmark. ARB stated during the June 11th workshop that the Board directed them to move forward with capacity credits for ZEV infrastructure while retaining the 20% target carbon intensity reduction over the life of the program. Thus, capacity credits can be utilized by regulated parties to demonstrate compliance; however, capacity credits will be excluded from calculating the carbon intensity of the fuel mix at the end of a compliance period. There is no safeguard or alternative for regulated parties if the carbon intensity of the actual fuel mix exceeds the carbon intensity benchmark for a given compliance period. There is no defined recourse to address how the gap will be reconciled among regulated parties who have complied with the regulation by purchasing credits which may include capacity credits. (VALERO2_FF11-1)

> **Agency Response:** Staff proposed that credits generated for ZEV infrastructure may be used for compliance like any other credit generated under the program. The only differentiation between types of credits will occur when staff calculates the GHG emissions reductions attributable to the program. This attribution calculation will not affect the compliance status of stakeholders.

I-3.4. *Other Means to Spur Installation of ZEV Infrastructure*

Comment: b. Other means are available to achieve the goals of Executive Order B-48-18 and spur installation of ZEV infrastructure

CARB has rationalized the proposed ZEV infrastructure crediting provisions by suggesting they are necessary to comply with Executive Order B-48-18, which directs "…State entities [to] work with the private sector and all appropriate levels of government to spur construction and installation of 200 hydrogen fueling stations and 250,000 zero-emission vehicle chargers, including 10,000 direct current fast chargers, by 2025." While the order directs agencies to "recommend ways to expand zero-emission vehicle infrastructure through the LCFS program," it certainly does not require the sort of crediting mechanism presently proposed by CARB.

RFA believes the most direct and effective means of spurring construction and installation of the desired ZEV refueling infrastructure would be for the state to issue grants or guaranteed loans. There are numerous examples of state and federal programs where this type of approach has been highly effective in driving installation of alternative fuel infrastructure. This would facilitate achievement of the goal to install the

desired infrastructure without jeopardizing the integrity of the LCFS credit mechanism. (RFA3_FF30-3)

> **Agency Response:** As the commenter states, Executive Order B-48-18 specifically calls for recommendations for expansion of ZEV infrastructure through the LCFS. The Governor issued this Executive Order with the knowledge that the CEC currently issues grants for ZEV infrastructure through its ARFVTP program, and specifically called on the LCFS program to further support this effort. The LCFS by design uses credits and deficits as its means of accomplishing reductions in the carbon intensity of transportation fuels in California. It is appropriate, therefore, that the LCFS mechanism to support ZEV infrastructure be facilitated by credit generation through the program.

I-3.5. *Aligning with other Jurisdictions*

Comment: While credit generation for infrastructure is a historical departure for the LCFS, it is similar to British Columbia's Part 3 agreement under the Renewable & Low Carbon Fuel Requirements Regulation. To align with British Columbia while maintaining fuel neutrality, REG suggests opening up opportunities for liquid low carbon fuels like biodiesel and ethanol through means like underground storage tank (UST) replacement or blender pumps. For biodiesel, the credit generation calculation would be for tanks that would go from a B5 to B20 compatibility. For example, a retail station that does one million gallons of ULSD annually could be eligible for up to 1,200 LCFS credits (98.44 Benchmark-35 avg biodiesel CI x 126.13 x 0.000001 x 150,000 gallons (B5 = 50K; B20 = 200K; 200K -50K)). We believe that a liquid fuel proposal like the HRI proposal could also benefit from a CI and blend threshold requirement, such as B20 with biodiesel having a CI less than 40. We agree that there should also be a cap of total credits like the FCI and HRI program as well as for the individual project so that LCFS credits don't entirely pay for a UST replacement. (REG3_FF44-13)

> **Agency Response:** Staff appreciates that there may be infrastructure constraints in other fuels and also acknowledges the specific suggestion for implementation of crediting for underground storage tanks or blender pumps. However, the fuels served by such infrastructure do not have equivalent criteria pollutant performance to ZEV fuels. Staff is not proposing credit for such infrastructure at this time.
>
> Staff also appreciates the recognition from stakeholders that other analogous programs—such as British Columbia’s Renewable & Low Carbon Fuel Requirements Regulation—have had explicit support for infrastructure investment in the same system as credits based on low carbon fuel sales/use. Such examples prove that infrastructure credits and traditional LCFS fuel-quantity credits can co-exist without major programmatic issues.

I-3.6. *Allow Credit Generation for Installation of All Low-Carbon Alternative Fuel Infrastructure*

Comment: c. If CARB proceeds to adopt the ZEV infrastructure crediting mechanism as outlined in Section 95486.2, it should broaden its scope to allow credit generation for installation of *all* low-carbon alternative fuel infrastructure

Notwithstanding the concerns expressed above, if CARB moves forward with the proposed ZEV infrastructure crediting mechanism, it should broaden the provision to also allow credit generation for the installation of *all* infrastructure that facilitates greater distribution and consumption of low-carbon alternative fuels.

As referenced above, many low-carbon alternative fuels have contributed toward the achievement of the LCFS program's goals to date. Biogas, biodiesel, renewable diesel, and ethanol are among the fuels that have generated substantial carbon reductions under the LCFS. These fuels can play an even larger role in decarbonizing the state's transportation sector moving forward. However, for the full potential of these fuels to be recognized, CARB must maintain a fair and equitable approach to implementation of the LCFS.

Thus, "…to ensure that **all fuels that contribute to the goals of the LCFS are treated equitably**…"[6], CARB should allow credit generation for all low-carbon alternative fuel infrastructure. This should include storage vessels and dispensers for biogas, E85 and mid-level ethanol blends, B20 and B100 biodiesel blends, and other fuels that have the potential to contribute meaningful carbon reductions under the LCFS.

[6] California Air Resources Board. March 5, 2009. "Proposed Regulation to Implement the Low Carbon Fuel Standard, Volume I, Staff Report: Initial Statement of Reasons," at ES-32. (emphasis added)

In fact, broadening the provision to allow credit generation for installation of low-carbon liquid fuels like E85 could spur accelerated growth in the use of low-carbon vehicle technologies that combine biofuel-powered fuel cells with electric powertrains, such as Nissan's e-Bio fuel cell. The e-Bio technology uses ethanol as the feedstock for an onboard fuel cell, which in turn generates electricity to power the vehicle's drivetrain. Nissan has chosen to commercialize the e-Bio fuel cell technology in Brazil because retail ethanol refueling infrastructure is broadly available there. Equitably allowing credit generation for all alternative fuel refueling infrastructure would drive manufacturers to commercialize this type of innovative technology in California rather than overseas. (RFA3_FF30-4)

> **Agency Response:** Please see Response I-3.1, Departure from Fuel Neutral Approach and would not Represent Actual GHG Emission Reductions, in this chapter and Response I-3.5 in this chapter regarding crediting other fuels. Regarding the Nissan vehicle model cited by the commenter, staff is excited to see potential future drivetrain technologies entering the market, and hopes to see similar technologies develop and commercialize within the United States. However, a single vehicle model of an innovative technology is not enough to justify heavy investment in LCFS credits for developing that technology.

I-3.7. *Provision goes Against Scoping Plan*

Comment: Calgren questions the wisdom of this proposed amendment. Allowing one or two types of renewable vehicle refueling facilities to generate credits based upon capacity while other types must report based upon carbon avoided creates a dangerous hierarchy; with all due credit to the Governor's office, they are attempting to pick winners and losers rather than letting science take its course. This goes directly against the ARB 2030 Climate Change Scoping Plan. The Scoping Plan calls for a "balanced mix of strategies" to provide California with "'the greatest level of certainty in meeting the [climate] target at a low cost while also improving public health, investing in disadvantaged and low-income communities, protecting consumers, and supporting economic growth, jobs and energy diversity." The proposed amendment effectively has narrowed the range of acceptable fuel technologies. This change risks sending the message that the State will ignore CI reduction if it results from "disfavored biofuels". Yet many such "disfavored biofuels," such as ethanol and biodiesel produced in needy parts of the state, such as the Central Valley, support a clean energy economy. This provides more opportunities for all Californians, provides a more equitable future with good jobs and less pollution for all communities, and improves the health of all Californians by reducing air and water pollution. The Scoping Plan also calls to increase production of renewable gas to support the reduction of Short-Lived Climate Pollutants. With the state turning to an electric- and hydrogen-only policy, many of the benefits for renewable natural gas as vehicle fuel will be lost.

We would like to warn ARB on the effect on the Low Carbon Fuel Standard program with the adoption of this change. The programs continued validity is in jeopardy with a policy that clearly shows that the ARB is no longer fuel neutral. (CRF2_FF42-2)

> **Agency Response:** Please see Response I-3.1, Departure from Fuel Neutral Approach and would not Represent Actual GHG Emission Reductions, in this chapter. Staff disagrees that the addition of section 95486.2 contradicts the 2017 Scoping Plan, and challenges the assertion that these proposed provisions demonstrate a Statewide shift towards an electric- and hydrogen-only policy. California's policies in general continue to provide a balanced mix of strategies to reduce GHG emissions while minimizing cost and improving public health. Moreover, the LCFS will continue to support all low carbon fuels used in the State. HRI and FCI crediting is limited to a maximum of five percent of program credits and therefore will not substantially diminish the value of other low carbon fuels relative to the baseline case, or directly affect credit generation by entities reporting non-ZEV fuel transactions.

I-3.8. Multiple Comments: *Infrastructure Credits and Actual Emissions Reductions*

Comment: We acknowledge both the Governor's executive order and the Board resolution regarding infrastructure capacity. However, we remain concerned that this proposal moves the LCFS program from its historical roots of requiring *actual reductions in carbon* in order to qualify for credits. This has been the most important aspect of the

program in ensuring the residents of California enjoy actual reductions in carbon loading and the benefits in cleaner air and potentially lessened climate change impacts. (REG3_FF44-12)

Comment: The proposed Zero Fueling Infrastructure Crediting Provisions provide credits for capacity rather than actual use. Providing credits for capacity will not achieve the same GHG or criteria pollutant benefits as the existing LCFS. (GROWTHENERGY2_FF56-45)

> **Agency Response:** Staff acknowledges that credits generated under the proposed infrastructure crediting provisions should not be misinterpreted to represent direct GHG emissions reductions. However, encouraging ZEV infrastructure expansion is expected to result in indirect benefits, as higher-levels of infrastructure availability will enable greater ZEV penetration in the California market. ZEVs provide a unique combination of both GHG and criteria pollutant benefits and would aid in attainment of California's climate change and air quality goals. Please see also Response I-3.1, Departure from Fuel Neutral Approach and would not Represent Actual GHG Emission Reductions, in this chapter.

I-3.9. Multiple Comments: *Insufficient Time to Comment on the ZEV Infrastructure Proposals*

Comment: In the 15-day notice, ARB proposes to greatly expand the credits for EV and HEV vehicle refueling infrastructure. In the original proposal, credit is given for fuel used by these vehicles. But in the 15-day notice, ARB proposes to give credits to infrastructure built to refill EVs and HEVs based on refueling capacity, rather than fuel use. ARB proposes some limits on the size of these credits in any one-quarter of a year, and also the life of these credits. But such "capacity" credits achieve no GHG emission reductions, like the actual fuel use.

The proposal appears to be hurriedly developed, and there is not sufficient time available for the public to comment on the concerns that this raises. It is not clear why ARB did not propose this at an earlier date. Accordingly, additional time for public comment should be permitted.

To the extent ARB continues to propose capacity credits for HEVs and EVs, ARB should provide capacity credits for other low-CI alternative fuels, including E15. Notably, there are no capacity credits for E15 refueling facilities for flexible fuel vehicles (FFVs) under the proposed amendments, which could likewise increase the use of low GHG biofuels. (GROWTHENERGY2_FF56-63)

Comment: Ultimately, staff must move forward in this area. Whatever is ultimately adopted will have a profound impact on the current program and will set a precedent for years to come. However, given the challenges and the possible alternatives we have highlighted, we suggest staff withdraw the current proposal and engage in a broader stakeholder development process. While there is still time to do so and have a final proposal to the Board in the Q4 timeframe which staff have indicated is their goal, we

would argue it is more important to ensure the ***right*** program is developed and therefore have staff take whatever time is necessary to do so. (REG3_FF44-17)

> **Agency Response:** Regarding the commenter's suggestion that infrastructure credits do not represent actual greenhouse gas emissions, please see Response I-3.1, Departure from Fuel Neutral Approach and would not Represent Actual GHG Emission Reductions, in this chapter. Regarding the crediting of other fuels for infrastructure, please see Response I-3.5 in this chapter. Staff disagrees with the commenter's suggestion that insufficient time was allowed for the public to comment on the proposal. The concept of infrastructure crediting was first raised by stakeholders during the November 6, 2017 pre-rulemaking workshop and submitted as a written comment following that workshop. At the Board hearing on April 27, 2018, the Board members discussed the concept in some detail and directed staff in Resolution 18-17 to work with stakeholders to further develop the proposal as part of the current rulemaking. Staff subsequently held a workshop on June 11, 2018, at which the proposal was discussed in depth. This workshop was followed by release of the 1st 15-day modifications to the regulation text and the public was allowed 15-days to submit comments in response to these modifications. Staff held another workshop on August 8, 2018 at which additional modifications to the proposal were discussed. This workshop was followed by release of the 2nd 15-day modifications to the regulation text and the public was allowed an additional 17 days to submit comments in response to the modifications. Staff believes that this record of public engagement provided sufficient opportunity for the public to engage and comment on the proposal.

I-3.10. *Crediting True-Ups*

Comment: In sum, biofuels are required to conservatively generate credits or else face enforcement while hydrogen and DC fast charging station owners can generate credits representing GHG reductions that have not yet occurred nor may ever occur. We understand that staff would intend to implement a true up system to correctly reflect the real quantifiable GHG reductions from capacity crediting but such a true up methodology has not been put forth in the rulemaking package nor has it been discussed in detail. Interestingly, in previous comment letters, Clean Energy proposed a similar annual credit true up for biofuel producers who outperform their certified CI, but this proposal has been rejected on numerous occasions by staff who believe such a process would be "administratively burdensome". (CE4_FF52-8)

> **Agency Response:** Staff believes that the commenter is confusing crediting "true-ups" with the attributional analysis of program benefits. To date, staff has not provided retroactive crediting for "out-performing" a certified CI, and this was not changed. Similar to the attributional analysis included in the illustrative compliance scenario posted on August 15, 2018, staff will not include HRI and FCI credits in the calculation of program GHG benefits.

I-3.11. *Capacity Crediting Available for All Low Carbon Fuel*

Comment: Clean Energy understands that the concept of crediting for capacity was included in response to the Governor's Executive Order B-48-18, but the development of hydrogen and EV fueling infrastructure should not come at the expense of the integrity of LCFS program and its foundation of real GHG reductions and fuel neutrality. Incentives for hydrogen and EV infrastructure pursuant to the Governor's Executive Order can come from other areas outside of the LCFS program. If not, capacity crediting should be available to all low carbon fuel participating in the LCFS in order to maintain a performance based program of fuel neutrality. (CE4_FF52-9)

> **Agency Response:** Please see Responses I-3.1, Departure from Fuel Neutral Approach and would not Represent Actual GHG Emission Reductions, and I-3.4 in this chapter.

I-3.12. *Consistency with Legal Authority and Required Process*

I-3.12a. *Scoping Plan*

Comment: The proposal to provide LCFS carbon credits for ZEV fueling infrastructure must be included within the Climate Change Scoping Plan and meet the requirements of Health and Safety Code Section 38561.

According to Section 38561(a), the California Air Resources Board (CARB) must prepare and approve a Scoping Plan for achieving the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from sources or categories of sources of greenhouse gases. California's 2017 Climate Change Scoping Plan does not include the proposal to provide LCFS carbon credits for ZEV fueling infrastructure, and therefore, must be updated. (FHR2_FF9-2)

> **Agency Response:** Staff disagrees. The addition of limited ZEV infrastructure capacity provisions within the LCFS are consistent with and responsive to the 2017 Scoping Plan. These provisions were proposed to be included as an integrated element of LCFS amendments, and amendments to the LCFS were specifically recommended by the most recent Scoping Plan update. Pursuant to Health and Safety Code Section 38561, the Scoping Plan provides the broad framework for which major policies the Board plans to proceed with and programmatic direction on these policies. The 2017 Scoping Plan called for an LCFS achieving at least 18 percent reduction in carbon intensity by 2030. It also recommended further development of policies such as the LCFS infrastructure crediting that "promote transportation fuel system infrastructure for electric, fuel-cell, and other emerging clean technologies that is accessible to the public where possible." (California's 2017 Climate Change Scoping Plan, page 76.) Moreover, the 2017 Scoping Plan does not limit the scope of subsequent rulemakings where additional information and public process on focused regulatory amendments may result in further refinements to measures and policies identified in that Scoping Plan.

I-3.12b. *Cost Effectiveness*

Comment: Furthermore, LCFS carbon credits issued to support ZEV fueling infrastructure must meet the cost-effectiveness requirements within Section 38561(a) and (b). According to Section 38561(d), “cost-effective” or “cost-effectiveness” means the cost per unit of reduced emissions of greenhouse gases. By CARB staff's own admission during the June 11, 2018 workshop, these credits will not represent actual greenhouse gas emission reductions. As a result, any LCFS carbon credits issued by CARB and purchased at any cost by fuel reporting entities to retire carbon deficits for the purposes of compliance would not represent cost-effective greenhouse gas emission reductions. (FHR2_FF9-3)

> **Agency Response:** The commenter’s point is incorrect because the commenter confuses layers of consistent authority. The most recent (2017) Scoping Plan update was approved pursuant to applicable legal requirements, and these LCFS amendments are consistent with that Scoping Plan update and approved pursuant to its own applicable legal requirements. First, these ZEV infrastructure credits are not designed to represent direct GHG emission reductions. Please see Responses I-3.1, Departure from Fuel Neutral Approach and would not Represent Actual GHG Emission Reductions, and I-3.4 in this chapter.
>
> Second, the cost-effectiveness requirement from Section 38561(d) in the full context is as follows:
>
> > The State Board shall evaluate the total potential costs and total potential economic and noneconomic benefits of the plan for reducing greenhouse gases to California's economy, environment, and public health, using the best available economic models, emission estimation techniques, and other scientific methods.
>
> As CARB conducted the Scoping Plan update in 2017 this provision was complied with in full. That Plan contains direction to continue and strengthen implementation of the LCFS, with increasing stringency of at least 18 percent reduction in carbon intensity. (California’s 2017 Climate Change Scoping Plan, page 80.) Following that direction, CARB initiated the rulemaking process, which has its own requirements for evaluation of economic impacts, including the SRIA. CARB complied with all of these applicable requirements pursuant to open and extensive public process, and was fully transparent about the costs and benefits of the Scoping Plan as a whole, and of the detailed LCFS amendments.

I-3.12c. *Coordinating with Other State Agencies to Avoid Exceeding Capital Costs*

Comment: As part of Scoping Plan requirements within Section 38561(a), CARB is also required to consult with all state agencies to ensure that the greenhouse gas emissions reduction activities to be adopted and implemented are “complementary, nonduplicative, and can be implemented in an efficient and cost-effective manner”.

Additionally, in Section 38561(c) CARB must consider all relevant information pertaining to greenhouse gas emissions reduction programs in other states, localities, and nations. However, the proposal does not consider if ZEV fueling infrastructure projects have or will also receive funding from other federal, state or local programs, such as the California Cap & Trade Program or from the California Public Utility Commission. As a result, infrastructure projects could receive multiple government subsidies, including the proceeds from LCFS carbon credit sales, that may exceed actual capital costs. (FHR2_FF9-4)

> **Agency Response:** As explained generally in Response I-3.12b in this chapter, staff disagrees with commenter's repeated suggestion that specific requirements applicable to Scoping Plan development apply to this rulemaking.

I-3.12d. *Discriminatory Practices*

Comment: By issuing carbon credits to support ZEV fueling infrastructure, CARB is creating a discriminatory preference for hydrogen and electricity over other low carbon fuels contrary to the equitable treatment requirements of Health and Safety Code Section 38562(b)(1).

CARB has not issued or contemplated the issuance of LCFS carbon credits for other low carbon fuel production or infrastructure investments. With this proposal, CARB is also disregarding the significant capital investments (possibly stranding these assets) already undertaken by other low carbon fuel producers and will create a disincentive for future investments into the production and distribution of other-low carbon fuels. (FHR2_FF9-5)

> **Agency Response:** Staff believes that the ZEV infrastructure capacity crediting provisions are consistent with all applicable authorities. Health and Safety Code section 38562(b) does not apply to the LCFS, as explained in response to GROWTHENERGY1_B4-33 in the Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

I-3.12e. *Real and Permanent GHG Reductions*

Comment: By adopting a regulation to Issue LCFS carbon credits for ZEV fueling infrastructure, CARB will not meet the requirements of Health and Safety Code Section 38562(d)(l) that greenhouse gas emission reductions achieved are real and permanent.

Again, by CARB staff's own admission during the June 11, 2018 workshop, these carbon credits will not represent actual greenhouse gas emission reductions. In addition, these carbon credits are proposed to be provided for a period of 15 years for hydrogen refueling and 5 years for electric vehicle charging infrastructure, starting with the quarter following application approval and based upon refueling capacity and station uptime/availability. Although the Summary of the proposed modifications indicates that carbon credits will not be provided to stations that provide no throughput, a threshold throughput quantity is not established within the proposed regulations, and

infrastructure investors could receive LCFS carbon credits only after dispensing nominal quantities of hydrogen or electricity. (FHR2_FF9-6)

> **Agency Response:** Staff believes that the ZEV infrastructure capacity crediting provisions are consistent with all applicable authorities. As clarified throughout this rulemaking record, the ZEV infrastructure capacity credits are not intended to represent "GHG emissions reductions" for purposes of Health and Safety Code section 38562(d).

I-3.12f. ***Modifications not Sufficiently Related to Original Proposal***

Comment: Part II, Section B of these comments explains why the Proposed Amendments and Proposed Modifications should receive additional input from the public. Specifically, since 2009, the LCFS has been based on a system under which regulated parties would receive credits based on carbon intensity ("CI") and actual reductions in greenhouse gas emissions. The Proposed Modifications depart from the longstanding function and intent of the LCFS regulation, and propose to provide credits for the development of hydrogen and electricity charging infrastructure and unused capacity; in order words, credits would no longer be tethered to direct reductions in emissions. CARB staff itself has acknowledged these modifications are "certainly a philosophical departure from what the program has been about in the past . . . ." (Exhibit "D.") In light of this significant change in both philosophy and function, a 15-day review process is insufficient under the Government Code. The Proposed Modifications are not "sufficiently related" to the original text, and therefore a 45-day review period is required under the California Administrative Procedure Act, Govt. Code, § 11350, et seq. (the "APA"). (GROWTHENERGY2_FF56-5)

> **Agency Response:** Please see response to GROWTHENERGY2_FF56-23 in the Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

I-3.12g. ***Inconsistent with Authority***

Comment: Part II, Section C urges CARB not to consider the Proposed Modifications on the basis that they would not "achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from those sources or categories of sources, in furtherance of achieving the statewide greenhouse gas emissions limit," as required under AB 32. (Health & Saf. Code, § 38560.5, subd. (c).) (GROWTHENERGY2_FF56-7)

> **Agency Response:** Staff believes that the proposed modifications are consistent with all applicable authorities including Health and Safety Code section 38560.5.

I-3.12h. ***AB 32 Actual GHG Reductions***

Comment: A. If CARB Issues Credits for Electricity and Hydrogen Capacity, it should also Issue Credits for Biofuel Infrastructure

As explained below, CARB should not consider the Proposed Modifications, as AB 32 and SB 32 do not authorize credits for underutilized capacity that is not tied to actual greenhouse gas emissions reductions. (See *infra* at § II.C.) In the event CARB does consider the Proposed Modifications, however, CARB should include infrastructure capacity credits for ***all*** low CI alternative fuels.

CARB has no rational basis to treat electricity and hydrogen in a manner different from other alternative fuels. While electricity and hydrogen have relatively low CI values, and CARB has stated a need to increase infrastructure associated with the delivery of those fuels to end-users, the same can be said for a wide-range of other fuels. Indeed, numerous alternatives fuels have a similar or lower CI value than electricity and hydrogen (even when EERs are included), while the use of those fuels is likewise limited by infrastructure. There is no lawful basis articulated in the record for this differential treatment of alternative fuels across the LCFS regulation, much less a rational basis.

As such, to the extent CARB considers providing credits for generating capacity for electricity and hydrogen, it should do the same for all low-CI alternative fuels. (GROWTHENERGY2_FF56-22)

> **Agency Response:** Staff disagrees with the commenter's alternative suggestions that CARB is either unauthorized to implement the proposed ZEV capacity crediting provisions within the LCFS, or that if authorized, capacity credits should be available for all low carbon fuels. Please see Response I-3.1, Departure from Fuel Neutral Approach and would not Represent Actual GHG Emission Reductions, in this chapter for a summary explanation of the authority, direction, and rationale supporting the proposed provisions.

I-4. *FSE Availability*

I-4.1. Comment: FirstElement Fuel recommends an uptime metric that can push the industry to a higher standard of excellence, and provide a basic degree of customer satisfaction. We believe that the current proposal for an "uptime" multiplier provides too large of a benefit for operators that only achieve 80% or 90% availability at a station. Based on our experience in operating stations, 90% uptime is unacceptable for customer satisfaction, and it requires far less effort and resources than achieving the >97% that we believe provides a basic level of customer satisfaction.

As an initial proposal, FirstElement Fuel would like CARB staff to consider the following uptime multiplier, and we also gladly offer further discussion and collaboration on this topic:

97-100% availability	Applicant receives 100% of available credits
94-97% availability	Applicant receives 90% of available credits
91-94% availability	Applicant receives 80% of available credits
88-91% availability	Applicant receives 70% of available credits
85-88% availability	Applicant receives 60% of available credits
82-85% availability	Applicant receives 50% of available credits
79-82% availability	Applicant receives 40% of available credits
76-79% availability	Applicant receives 30% of available credits
73-76% availability	Applicant receives 20% of available credits
70-73% availability	Applicant receives 10% of available credits
<70% availability	Applicant receives no credits

(FEF1_FF71-6)

Agency Response: Staff did not propose to include the uptime multiplier suggested by the commenter. The capacity credit equation already scales HRI credit generation using the reported uptime of the station, which staff believes is sufficient incentive to maintain stations at a high level of availability. In addition, introducing availability thresholds is likely to lead to conflict for stakeholders that fall just below the different levels suggested, which can be avoided by directly accounting for the actual up-time reported in the credit generation calculation.

I-4.2. Comment: While LADWP supports the infrastructure crediting concept as a whole, LADWP recommends amendment to ARB's proposal that the "FSE must be located in California and open to the public for charging 24 hours per day, 7 days per week (24/7)," and that "open to the public" means "no obstructions or obstacles exist to preclude vehicle operators from entering the FSE premises, no access cards or personal identification (PIN) cards are required for the FSE to dispense fuel…" LADWP believes that the 24/7 availability and the no obstructions or obstacles requirements are too restrictive and may exclude optimal locations in need of DCFC stations. These locations may include, but are not limited to, Government buildings and recreational areas where the public parking lots are not open 24/7, may be gated (which could be considered an obstruction), or charges a fee to park. LADWP recommends removing the 24/7 requirement, clarifying the definition of obstruction or obstacles, and suggest prorating capacity credits based on the operating hours of the charging station. (LADWP2_FF10-7)

Agency Response: Staff agrees with the commenter and proposed modifications to the language in the 2nd 15-day modifications. In sections 95486.2(b)(1)(A) and 95486.2(b)(2)(I), staff proposed the FSE must be located in California and open to the public for charging, and must report the total permitted hours of operation in the FCI application. If the permitted hours of operation for the site are less than 24 hours, the applicant must provide documentation from a permitting authority demonstrating that daily permitted hours of operations are limited. This change would ensure the FSE availability is accounted based on the total permitted hours of operation which would be used for FCI credit

calculation pursuant to section 95486.2(b)(5). This would allow charging equipment installed in locations with restricted access hours to be eligible for infrastructure credits, such as in State and National Parks.

I-5. Multiple Comments: *Carbon Intensity and Renewable Content Requirement for HRI Crediting*

Comment: In recognizing HRI Crediting is being made late in the regulatory process Air Products recommends additional work in finalizing the HRI Crediting hydrogen pathway eligibility requirements in the following areas:

1) HRI Maximum Carbon Intensity – Section 96486.2(a)(4)(f)1 requiring hydrogen to meet an unadjusted carbon intensity (CI) of 75 g CO2e/MJ or less will restrict hydrogen supply pathway options in California. For example, steam methane reforming with biomethane from landfill pathway HYB is not eligible for HRI crediting. Even water electrolysis using California grid power pathway (HYEG) with 30% renewable content carries a carbon intensity of 164 gCO2e/MJ or greater than 2.2X the HRI crediting eligibility requirement. Air Products recommends Section 96486.2(a)(4)(f)1 be revised to allow for all hydrogen supply sources to qualify for HRI pathway crediting. HRI crediting can still be accrued based of the CI reduction of hydrogen supply with the Energy Economic Ratio (EER) factored in to the calculation of HRI Credits. Alternatively, an EER adjusted carbon intensity (CI) of 75g CO2e/MJ or less could be acceptable.

2) Minimum Renewable Content - Air Products recognizes the requirement of 33 percent renewable energy content of hydrogen supply in SB1505 and is unsure why a renewable content of 40% or greater is required for HRI crediting eligibility. Air Products recommends Section 96486.2(a)(4)(f)2 be consistent with SB1505 renewable content of 33 percent or greater. (AP1_FF16-3)

Comment: Requirements to Generate Credits: the hydrogen community previously recommended a requirement for company-wide hydrogen supply to be a "weighted average CI of 75 gCO2e/MJ (non-EER adjusted) for dispensed fuel or a renewable content of 40 percent or greater." Note the importance of "or" in this requirement, since both requirements go beyond the requirements of SB 1505 (Lowenthal, 2006)[1], allowing efficient and effective outcomes in increasing renewable content and decreasing carbon intensity of hydrogen supply while also building station capacity.

[1] SB 1505 (2006) required: (a) "… on a statewide basis, no less than 33.3 percent of the hydrogen produced for, or dispensed by, fueling stations that receive state funds be made from eligible renewable energy resources…"; and (b) "… on a statewide basis, well-to-wheel emissions of greenhouse gases for the average hydrogen powered vehicle in California are at least 30 percent lower than emissions for the average new gasoline vehicle in California when measured on a per-mile basis."

The currently proposed criteria for eligible hydrogen production states "weighted average CI of 75 gCO2e/MJ (non-EER adjusted) for dispensed fuel and a renewable content of 40 percent or greater." Note the use of "and" in this requirement. With this criterion, the only lookup pathway eligible for this program would be HYER, electrolysis produced with wind or solar (per *CA-GREET 3.0 Lookup Table Pathways-Technical*

Support Documentation, Table F.3). All other pathways using renewable feedstocks including electrolysis from the grid (HYEG) and renewable natural gas pathways (HYB and HYBL) would be excluded as they have a CI > 75 gCO2e/MJ (non-EER adjusted).

To develop a viable hydrogen supply industry with the increasing renewable content and decreasing carbon intensity incentivized by the HRI, it is imperative that all renewable pathways be eligible under this program and, as such, we request that eligibility requirements be changed to **"weighted average CI 40 percent lower than the current year gasoline standard pathway (with EER adjustment) for dispensed fuel and a renewable content of 40 percent or greater."** This approach also keeps targets directly linked to those of the overall program. (H2IND2_FF17-6)

Comment: Requiring company-wide hydrogen supply to be a weighted average CI of forty percent (40%) below the current year gasoline standard pathway (with EER adjustment) for dispensed fuel and a renewable content of forty percent (40%) or greater would ensure development of hydrogen supply that exceeds the requirements of SB 1505 (Lowenthal, 2006), while allowing flexibility in increasing renewable content, decreasing carbon intensity, and developing station capacity. (SHELL2_FF57-5)

> **Agency Response:** In response to stakeholder comments, staff proposed to increase the maximum company-wide weighted average CI to 150 gCO_2e/MJ. After incorporating the Energy Economy Ratio (EER) adjustment of 2.5 for light-duty hydrogen fuel cell vehicles, the maximum CI still meets the CI requirement of SB 1505 (30 percent reduction relative to gasoline). This change would provide more flexibility for hydrogen production and transport methods (such as liquid hydrogen delivery).
>
> The renewable content requirement must be at least 33 percent to comply with SB 1505. Staff expects that requiring a company-wide weighted average renewable content percentage of 40 percent is achievable by industry, especially given the decision to relax the CI requirement to 150 g/MJ, and this requirement is consistent with the goal of promoting lower-CI, sustainable transportation fuel.

I-6. *Capacity Expansion*

I-6.1. *Expanding HRI Crediting*

Comment: 3) <u>HRI Crediting for Expanded HRI Refueling Capacity</u> – The proposed scope of HRI Crediting for expanded HRI refueling capacity in section 95486.2(a)(7) applies to hydrogen fueling stations already generating HRI credits. Air Products requests that HRI Crediting for expanded station capacity be extended to the existing California retail stations awarded through the first four CEC awards. Otherwise, early market hydrogen fueling station owners and suppliers will be at a competitive disadvantage to newer larger stations operating in the same retail hydrogen station network. We foresee possible closure of hard earned early market retail fueling stations if HRI Crediting is not available to support refueling station capacity expansions of existing retail hydrogen stations. (AP1_FF16-5)

Agency Response: Existing hydrogen stations are eligible to apply for HRI credits, assuming they meet the eligibility requirements of section 95486.2(a)(1). Staff maintains that a station must already be receiving HRI credits in order to apply for recognition of expanded station capacity. Stations may also be expanded before applying for HRI credits in the first place, in which case the newly expanded capacity would become the certified capacity for the station.

I-6.2. Multiple Comments: *Applications for Expanded HRI Refueling Capacity*

Comment: Applications for Expanded HRI Refueling Capacity: we encourage **resetting the 15-year crediting period for incremental increases in capacity**. This would put station expansion on par with new station development for investment, and would avoid the potential unintended result of over-building new station capacity while neglecting existing "mid-life" stations. We also encourage **setting the required station throughput for expansion eligibility at 35%** to enable expansion in refueling capacity to support increasing adoption of fuel cell electric vehicle in areas of rapid market growth. Expansion of station capacity will be important in a success case of increasing contribution from hydrogen and fuel cell electric vehicles to California's emission reduction goals. (H2IND2_FF17-11)

Comment: Setting the threshold for qualifying capacity expansion at thirty-five percent (35%) utilization and re-setting the fifteen-year (15-year) crediting period for incremental increases in capacity would avoid a potential unintended result of over-building new station capacity while neglecting existing "mid-life" stations. (SHELL2_FF57-9)

Agency Response: Staff disagrees with the recommendation to reset the 15 year crediting period after station expansion. The proposal allows for applications to be considered and approved through 2025 and upon approval generate credits for up to 15 years. Resetting the crediting period upon expansion would potentially result in the provision generating credits for stations well beyond staff's desired end date of 2040. Staff also disagrees with the recommendation to set the required station throughput for expansion eligibility at 35 percent. Staff believes that the 35 percent threshold proposed by the commenter could provide excessive infrastructure credit revenue for a station that does not yet need an expansion.

I-6.3. *Applications for Expanded FCI Refueling Capacity*

Comment: ChargePoint recommends that the FCI Pathway Requirements include serial number by the OEM. The FCI Pathways encourage colocation, but without serial number as part of the registration requirement, it will be difficult to divvy up credits for the site. ChargePoint would also like to respectfully point out that in cases of Expanded FCI Capacity, there should not necessarily a requirement for an updated "number" of DCFC, just a requirement for reporting the increased capacity. ChargePoint's DCFC technology is modular and scalable, allowing us to add capacity without adding stations (or ripping and replacing stations).

Please see below for a chart of the estimated cost of electricity, including demand charges, in the three major IOU service territories in California, along with LADWP and SMUD.

Sessions per Day per Location - Annual Driver Fee's Collected

		Demand and Meter Charges	5	10	15	20	25	30	35	40	45	50	<< Sessions/Day/Location
			$ 9,125	$ 18,250	$ 27,375	$ 36,500	$ 45,625	$ 54,750	$ 63,875	$ 73,000	$ 82,125	$ 91,250	<< Annual Driver Fee's Collected
Two 50kW Chargers (100kW total)	PG&E	$ 19,554	$ (10,429)	$ (1,304)	$ 7,821	$ 16,946	$ 26,071	$ 35,196	$ 44,321	$ 53,446	$ 62,571	$ 71,696	Amount Positive or Negative just based on demand and meter charges - does not include energy charges, maintenance or operational expenses
	SCE	$ 18,225	$ (9,100)	$ 25	$ 9,150	$ 18,275	$ 27,400	$ 36,525	$ 45,650	$ 54,775	$ 63,900	$ 73,025	
	SDG&E	$ 44,150	$ (35,025)	$ (25,900)	$ (16,775)	$ (7,650)	$ 1,475	$ 10,600	$ 19,725	$ 28,850	$ 37,975	$ 47,100	
	LADWP	$ 17,868	$ (8,743)	$ 382	$ 9,507	$ 18,632	$ 27,757	$ 36,882	$ 46,007	$ 55,132	$ 64,257	$ 73,382	
	SMUD	$ 10,445	$ (1,320)	$ 7,805	$ 16,930	$ 26,055	$ 35,180	$ 44,305	$ 53,430	$ 62,555	$ 71,680	$ 80,805	

Annual Sessions per Day per Location - Annual Driver Fee's Collected

		Demand and Meter Charges	5	10	15	20	25	30	35	40	45	50	<< Sessions/Day/Location
			$ 9,125	$ 18,250	$ 27,375	$ 36,500	$ 45,625	$ 54,750	$ 63,875	$ 73,000	$ 82,125	$ 91,250	<< Annual Driver Fee's Collected
Two 300kW Chargers (100kW total)	PG&E	$ 54,630	$ (45,505)	$ (36,380)	$ (27,255)	$ (18,130)	$ (9,005)	$ 120	$ 9,245	$ 18,370	$ 27,495	$ 36,620	Amount Positive or Negative just based on demand and meter charges - does not include energy charges, maintenance or operational expenses
	SCE	$ 49,905	$ (40,780)	$ (31,655)	$ (22,530)	$ (13,405)	$ (4,280)	$ 4,845	$ 13,970	$ 23,095	$ 32,220	$ 41,345	
	SDG&E	$ 129,654	$ (120,529)	$ (111,404)	$ (102,279)	$ (93,154)	$ (84,029)	$ (74,904)	$ (65,779)	$ (56,654)	$ (47,529)	$ (38,404)	
	LADWP	$ 52,932	$ (43,807)	$ (34,682)	$ (25,557)	$ (16,432)	$ (7,307)	$ 1,818	$ 10,943	$ 20,068	$ 29,193	$ 38,318	
	SMUD	$ 28,745	$ (19,620)	$ (10,495)	$ (1,370)	$ 7,755	$ 16,880	$ 26,005	$ 35,130	$ 44,255	$ 53,380	$ 62,505	

Annual Sessions per Day per Location - Annual Driver Fee's Collected

		Demand and Meter Charges	10	20	30	40	50	60	70	80	90	100	<< Sessions/Day/Location
			$ 18,250	$ 36,500	$ 54,750	$ 73,000	$ 91,250	$ 109,500	$ 127,750	$ 146,000	$ 164,250	$ 182,500	<< Annual Driver Fee's Collected
Four 150kW Chargers (600kW total)	PG&E	$ 472,383	$ (463,258)	$ (435,883)	$ (417,633)	$ (399,383)	$ (381,133)	$ (362,883)	$ (344,633)	$ (326,383)	$ (308,133)	$ (289,883)	Amount Positive or Negative just based on demand and meter charges - does not include energy charges, maintenance or operational expenses
	SCE	$ 97,425	$ (88,300)	$ (79,175)	$ (70,050)	$ (60,925)	$ (51,800)	$ (42,675)	$ (33,550)	$ (24,425)	$ (15,300)	$ (6,175)	
	SDG&E	$ 225,981	$ (216,856)	$ (207,731)	$ (198,606)	$ (189,481)	$ (180,356)	$ (171,231)	$ (162,106)	$ (152,981)	$ (143,856)	$ (134,731)	
	LADWP	$ 105,528	$ (96,403)	$ (87,278)	$ (78,153)	$ (69,028)	$ (59,903)	$ (50,778)	$ (41,653)	$ (32,528)	$ (23,403)	$ (14,278)	
	SMUD	$ 46,943	$ (37,818)	$ (28,693)	$ (19,568)	$ (10,443)	$ (1,318)	$ 7,807	$ 16,932	$ 26,057	$ 35,182	$ 44,307	

Annual Sessions per Day per Location - Annual Driver Fee's Collected

		Demand and Meter Charges	50	100	150	200	250	300	350	400	450	500	<< Sessions/Day/Location
			$ 91,250	$ 182,500	$ 273,750	$ 365,000	$ 456,250	$ 547,500	$ 638,750	$ 730,000	$ 821,250	$ 912,500	<< Annual Driver Fee's Collected
1,500kW Charging Depot	PG&E	$ 472,383	$ (463,258)	$ (289,883)	$ (198,633)	$ (107,383)	$ (16,133)	$ 75,117	$ 166,367	$ 257,617	$ 348,867	$ 440,117	Amount Positive or Negative just based on demand and meter charges - does not include energy charges, maintenance or operational expenses
	SCE	$ 239,985	$ (230,860)	$ (221,735)	$ (212,610)	$ (203,485)	$ (194,360)	$ (185,235)	$ (176,110)	$ (166,985)	$ (157,860)	$ (148,735)	
	SDG&E	$ 556,569	$ (547,444)	$ (538,319)	$ (529,194)	$ (520,069)	$ (510,944)	$ (501,819)	$ (492,694)	$ (483,569)	$ (474,444)	$ (465,319)	
	LADWP	$ 263,316	$ (254,191)	$ (245,066)	$ (235,941)	$ (226,816)	$ (217,691)	$ (208,566)	$ (199,441)	$ (190,316)	$ (181,191)	$ (172,066)	
	SMUD	$ 73,655	$ (64,530)	$ (55,405)	$ (46,280)	$ (37,155)	$ (28,030)	$ (18,905)	$ (9,780)	$ (655)	$ 8,470	$ 17,595	

Please note that we made the following assumptions/used the following information:

- We used publicly available information from EVgo on pricing ($0.20 per minute) and session length (average 25 minute sessions)
    - We did not factor in the assumption that EVgo raises price per minute for cars that charge at higher rates
- Color-coded delate numbers in the chart represent the difference between demand and meter charges owed vs. what driver revenue is estimated to be
- No demand limit was used on these sites to keep demand charges down (CHARGEPOINT3_FF39-6)

Agency Response: Please see Response I-5.1 in Chapter VI . If no additional equipment is needed for a capacity expansion, this information should be relayed clearly in the application. In addition, staff appreciates the data submitted in the comment.

I-6.4. *Proposed Cap on Credits from ZEV Fueling Infrastructure Pathways*

Comment: *The Proposed Cap on Credits From ZEV Fueling Infrastructure Pathways is Too Large and Non-Binding*

The modified text proposes that both Hydrogen Refueling Infrastructure (HRI) and DC Fast Charging Infrastructure (FCI) pathways be limited to credits equal to 2.5% of total LCFS credit generation for a given quarter. The proposed amount is too high and should be reduced, in order support actual emissions reductions from the LCFS and to better conform with the Board's intent when it moved to adopt Resolution 18-17.

In addition, **the current mechanism for enforcing the proposed 2.5% cap is, in fact, non-binding.** Under circumstances which could occur under a number of likely market and technological conditions, the current proposal would allow permits significantly in excess of the nominal 2.5% cap for each pathway to be repeatedly issued. This soft cap does not sufficiently assure the environmental integrity of the program.

We recommend CARB make the following changes:

Amend § 95486.2 (a) (3) to read:

Application Approval Process. The HRI application must be approved by the Executive Officer before the station owner may generate hydrogen refueling infrastructure credits. If HRI credits from all approved stations exceed ~~2.5~~ 1 percent of deficits in the prior quarter, the Executive Officer will ~~not approve additional HRI pathways and will not accept additional applications until HRI credits are less than 2.5 1 percent of deficits. HRI applications will be evaluated for approval on a first come, first served basis~~ apportion HRI credits equal to 1% of deficits in the prior quarter to all stations with an approved HRI pathway based on the station's proportional contribution to total HRI credit generation that quarter.

Amend § 95486.2 (b) (3) to read:

Application Approval Process. The FCI application must be approved by the Executive Officer before the applicant may generate FCI credits. If FCI credits from all approved FSEs exceed ~~2.5~~ 1 percent of deficits in the prior quarter, the Executive Officer will not approve additional FCI pathways and will ~~not accept additional applications until FCI credits are less than 2.5 1 percent of deficits. FCI applications will be evaluated for approval on a first come, first served basis~~ apportion FCI credits equal to 1% of deficits in the prior quarter to to all operational stations with and approved FCI pathway based on the station's proportional contribution to total FCI credit generation that quarter.

Rationale for reducing credit caps to 1%:

The 2.5% Caps Allow More Pollutant Emissions and Reduce Expected Emission Cuts from LCFS Below Scoping Plan Proposals

Under the proposed 20% LCFS CI target, assuming fuel demand equal to the "High Demand" scenario in the Illustrative Compliance Scenario calculator, the program generates a cumulative 332 million deficits under the LCFS program through 2030. The "Low Demand" scenario generates 287 million deficits. Compliance with the LCFS requires that deficits must be matched with credits, which represent a reduction in

emissions. The proposed infrastructure pathways would allow 5% of this deficit generation to be met with infrastructure credits, which do not represent actual reductions in emissions. Our modeling indicates that it is very likely that both HRI and FCI pathways will routinely generate enough credits to exceed the 2.5% ceiling multiple times through 2025.[5]

[5] Please see attached spreadsheet model and modeling memo for more detail.

Applications are accepted through 2025, though hydrogen stations can wait up to two years after the application is submitted to come online without penalty, and can re-submit their application after two years have elapsed, but with reduced duration of infrastructure credit eligibility. This implies that the number of stations eligible to receive credit is likely to continue growing even when applications are not being accepted, as approved, but not yet operational stations enter service. While the uncertainty involved in such modeling is admittedly high, the available evidence indicates that aggregate infrastructure capacity credit generation at or near 5% would be completely feasible and perhaps even likely during the 2020-2030 timeframe.

A 5% Reduction In LCFS Deficit Generation Could Compromise the LCFS Market and California's Ability to Attain GHG Targets.

The reduction in deficit generation will exert a significant downward pressure on LCFS credit prices, muting the signal which spurs investment in clean technologies. This exacerbates the downward price pressure resulting from the smoothing of the CI trajectory in the 2018-2022 period. Both the CARB's modeling[6] and recent independent modeling by Ceruology Inc.[7] indicate a robust supply of LCFS credits and a strong credit bank through the mid 2020's. Reducing demand by 5% from a market that would likely have had an approximate balance between supply and demand could dramatically reduce the amount of investment into supply, which will be necessary to meet California's long-term obligations.

[6] As reflected in all 20% target scenarios in the Illustrative Compliance Scenario calculator.

[7] https://nextgenamerica.org/californias-clean-fuel-future/

More importantly, reducing deficit generation by 5% will likely lead to a reduced LCFS credit price, which will reduce the incentive for further reductions in emissions; conventional market theory would anticipate that reducing credit demand by 5% will reduce long-run supply by about 5% as well. Losing that 5% of supply means losing the GHG emissions reductions reflected by those credits; in effect, the LCFS will yield approximately 5% fewer GHG reductions than it would have otherwise. Even if one accepts the premise that the infrastructure incentivized by HRI and FCI pathways yields deeper long-term emissions cuts, those cuts would likely not materialize until after 2030, due to limits on the rate of expansion by the state-wide ZEV fleet. Depending on modeling assumptions, the cumulative reduction in deficits due to infrastructure credits through 2030 is likely to be 12-16 million metric tonnes. These values could, under a variety of conditions, reduce the LCFS program's expected cumulative reductions below those expected under the 18% target originally proposed by CARB and which was the basis for modeling the LCFS' contribution to attainment of SB 32 targets under the scoping plan. **The proposed infrastructure capacity credits likely leave the**

LCFS weaker than the original 2017 discussion draft and potentially unable to meet its 2030 cumulative reductions targets under the scoping plan. Adding these infrastructure credits would allow deficit-generating entities, such as petroleum refiners, to produce and sell more fuel into the California market, which would drive up GHG emissions under the cap-and-trade program, increasing cap-and-trade credit prices and making attainment of SB 32 targets significantly more difficult.

Limiting HRI and FCI credits to 1% of total deficits, as in the proposed amended language above, limits the potential for HRI and FCI credits to disrupt market signals and restores over half of the cumulative emissions cuts which would otherwise be lost to these programs.

The Proposed 2.5% Limits Exceed the Board's Authorization in Resolution 18-17

At the April 28th Board meeting, several issues relating to the LCFS were discussed, which resulted in Board Resolution 18-17. The specific motion, by Members Berg and Gioia called for Resolution 18-17 to be approved "incorporating all the comments that [the Board] made here".[8] At the meeting, the most specific discussion about the proposed infrastructure credits was put forward by Dr. Sperling who said "... it won't be a big part of the total credits. It was estimated at one or two percent."[9]

[8] https://www.arb.ca.gov/board/mt/2018/mt042718.pdf Pg. 266.
[9] https://www.arb.ca.gov/board/mt/2018/mt042718.pdf Pg. 240

The proposal in the Modified Text proposes a program which would allow both HRI and FCI pathways to generate credits equal to 2.5% of total LCFS deficits, for a total of 5% of total deficits. As discussed below, the non-binding nature of this cap allows for significantly more than 2.5% of credits to be issued to either pathway in a given quarter and there are multiple likely deployment scenarios which would result in both HRI and FCI exceeding the 2.5% limit. This far exceeds the "one or two percent" which was the only stated comment relating to the scope of the proposed infrastructure capacity credits at the board meeting.

Limiting HRI and FCI credits to 1% of total deficits, as in the proposed amended language above, better conforms to the Board's guidance from the April 28th hearing.

Rationale for Switching from a Soft to a Hard Cap

A broad consensus emerged at the April meeting that infrastructure capacity credits should be limited in scope because they compete against actual emission reductions and represent a substantial deviation from the LCFS' established mechanisms of action. The guidance given by Dr. Sperling, which was the basis for the Resolution 18-17 indicated that there should be a meaningful limit on total permit generation from these pathways, in order to limit the risk of excessive allocation of permits through this pathway until there had been an opportunity to review the performance of these programs under real-world conditions.

The June 20th Modified Text articulates this limit as a threshold after which no new applications will be accepted. Per conversations with staff, this mechanism was chosen

because it was simple to implement and did not require an analytical process to develop and model alternatives. We certainly understand and support the desire to keep the LCFS as simple as possible, however **the proposed mechanism is significantly flawed in that it is not actually a cap on HRI and FCI permits, it merely imposes a temporary halt to the program's growth.** Under several reasonable scenarios, the proposed mechanism would allow infrastructure credits in excess of 2.5% of total LCFS deficits to be issued for one or more quarters each year through 2025 and possibly even a year or two after that. If the HRI and FCI pathways achieve their goals of achieving the targets laid out in Executive Order B-48-18, then it is extremely likely that there will be enough stations generating credit from these pathways to routinely exceed the 2.5% limit. The proposed mechanism, a temporary freeze on accepting applications is nominally a check against this, but in practice it is almost certain to be ineffective.

Applications for HRI pathways can be approved up to two years before the station enters service. If more than two years elapse between approval of an HRI application and the station entering service, can re-apply for HRI credits, the only penalty is that its eligibility for such credits drops from 15 years to 10 years. This means that the amount of HRI credits issued is likely to grow each quarter, *even if the Executive Officer ceases approving applications, as directed by § 95486.2 (a) and (b)*. The Executive Officer is not afforded any authority to reject applications or limit HRI credit issuance even if it is obvious, given the existing and imminently operational hydrogen fueling station capacity, that granting such applications will cause future HRI credit generation to exceed 2.5% of LCFS deficits.

For example, consider a hypothetical scenario in which 2nd quarter HRI credit generation is 100 tonnes below the 2.5% threshold. Even if no additional applications were accepted, it is entirely possible that 3rd and 4th quarter HRI credits would exceed the 2.5% limit as previously-approved stations come online. More importantly, the Executive Officer would have *no authority to reject or delay permit applications* received in the 2nd quarter for stations which would be operational in the 3rd or 4th quarter. The proposed cap mechanism would continue to approve applications even when doing so would incontrovertibly cause the program to exceed the cap in future quarters.

FCI pathways can also exceed the soft cap through similar mechanisms. Even though FCI pathways cannot be approved in advance of the station entering service, applications must be approved as long as *current-quarter* FCI credits do not exceed 2.5% of total deficits.

The outcome of this regulatory design is quite predictable. The Executive Officer will not approve applications when the system is currently exceeding the threshold, but the applications themselves will continue to accumulate during that period. As soon as credit generation drops below the 2.5% threshold, even if it is only for one quarter, the entire backlog of unprocessed applications can be approved, once again driving the system above the putative cap.

Under a scenario in which the 2.5% target is exceeded, applications will merely be delayed until the total number of permits issued drops below 2.5% of total deficits. *This is likely to happen at the start of each year, when LCFS targets increase*. At best, the proposed mechanism delays applications for a few quarters until the next target increase, but is completely compatible with an outcome in which the program issues HRI and/or FCI permits in excess of 2.5% of total deficits for one or more quarters every year. It is even compatible with a scenario which issues HRI or FCI credits equal to more than 2.5% of deficits *on a yearly basis.*

There is a simple solution which converts the current soft cap to a hard one, without the complexity of modeling expected future infrastructure credit generation: **Instead of rejecting applications when the cap is reached, the Executive Officer should apportion HRI and/or FCI credits equal to the amount of the cap among all parties which would have received such credits.** This structure guarantees that infrastructure capacity credit issuance does not exceed the specified cap. There are multiple apportionment methodologies which would be appropriate for this task. We suggest apportioning based on the proportion of total HRI credits generated that quarter, which preserves the basic principle of directing credits towards stations with the greatest amount of unused capacity. Alternatively, the proposed infrastructure credit provisions in the Modified Text generally give priority to stations based on earliest date of approval, using seniority to establish a hierarchy would be an acceptable alternative to proportional distribution, however unless the total credit generation per station were capped, this would likely lead to only a small number of stations receiving HRI or FCI credit. Some stakeholders, including NRDC and UCS, have indicated that they support a declining cap on total infrastructure credit per station. This mechanism, if set at appropriate levels, would allow apportionment based on seniority to function without excluding new stations from the provision.

We recognize that the proportional allocation proposal introduces a measure of uncertainty regarding the amount of credits a project can expect in any given quarter. We recognize this uncertainty can impede efforts to get projects approved, however we would note that projects are still eligible for 15 and 5 years of HRI and FCI credits, respectively, which allows time for a sufficient number of credits to be developed by each project. Given the substantial amounts of revenue available through this HRI and FCI credits, relative to likely capital costs[10], proportional apportionment of credits would at worst, delay full recoup of infrastructure costs for project developers. Under the Success Case, a 1200 kg hydrogen station could expect to receive over $3 million in revenue through 2025 alone, while retaining 10 more years of eligibility under the program. Even if rate of credit generation is slowed by proportional allocation, the station would still expect millions in total revenue, enough to offset the majority of station capital costs under most scenarios. Apportioning credits by date of application approval would reduce this uncertainty, but also reduce the number of projects which receive credit. Again, we are open to either method, though would suggest the proportional approach since it supports more stations, and in a more equitable fashion.

[10] See modeling memo and attached worksheet.

If the Current Proposal Succeeds in Meeting Infrastructure Targets, It Will Almost Certainly Exceed the 2.5% Threshold By A Significant Amount

The results of the attached modeling focus on scenarios in which the state achieves, or at least approaches, critical ZEV infrastructure deployment goals: 10,000 DC fast charger installations and 200 hydrogen fueling station installations. For both HRI and FCI, two scenarios for fuel consumption from the supported infrastructure are considered. The capacity-based credit formula yields fewer HRI and FCI credits as fuel consumption through supported infrastructure increases. For both HRI and FCI, *any scenario which meets the targets for infrastructure deployment set by Executive Order B-48-18 will exceed the proposed 2.5% threshold unless fuel sales exceed even highly optimistic projections.*

The Cerulogy case examined in the attached model represents a scenario in which 5.8 million ZEVs are deployed by 2030 and more than 1 million by 2025. This achieves the ZEV deployment target specified in B-48-18 and yields a significant consumption of electricity for transportation fuel, enough to satisfy over half of the total LCFS credit demand in 2030. This represents a reasonable vision of success in California's transition towards a predominantly zero-emission transportation future. Even under this fairly optimistic projection of electricity consumption, a DC fast charger installation trajectory compatible with attaining the 10,000 fast charger target specified in B-48-18, yields credit generation significantly in excess of the 2.5% threshold. **If the program succeeds, it will almost certainly exceed its intended limits to do so.** The HRI pathway shows similar behavior, even the Success Case, which assumes a very rapid growth in hydrogen consumption, exceeds 2.5% of aggregate credit in most years through 2025. As discussed above, the soft-cap mechanism specified in the Modified Text is incapable of ensuring actual HRI and FCI credit generation stays below the 2.5% threshold, it will likely result in massive numbers of permit approvals during the brief windows when targets increase and temporarily bring the number of deficits above the limit on HRI or FCI credit generation. **CARB should not adopt a policy which will violate its own rules on the road to success.**

The Proposed HRI and FCI Pathways Should Limit Per-Station Credit Generation to a Reasonable Fraction of Capital Cost

The proposed HRI and FCI pathways are intended to support the deployment of fueling infrastructure in advance of anticipated ZEV demand. This functionally solves the chicken-and-egg problem of infrastructure deployment in an immature market. By subsidizing much of the capital cost, early project developers are not subjected to undue risk that vehicle demand will not materialize quickly enough to support their investments. This basic principle is sound, and there is evidence from early deployment of EV charging infrastructure that can effectively support ZEV deployment.

We appreciate Staff's effort to design a system which rewards aggressive deployment of refueling and fast charging infrastructure, which will help improve the market's adoption of ZEVs. The credit calculations presented in § 95486.2 (a) (5) and (b) (5) present a system which reduces the risk to project developers, however they ultimate

allow project developers to receive revenue far in excess of likely capital investment in the stations, which would ultimately lead to windfall profits by project developers. While we recognize the State of California's role in reducing the risks of ambitious technological development to early movers in an area of critical importance, California policy should not deliver massive profit to developers irrespective of whether their product is actually used.

We recommend CARB add the following subsection to § 95486.2 (a) and (b), selecting HRI and FCI as appropriate :

(8) *Maximum Credit Generation Per HRI/FCI Application*

(A) Each station approved HRI/FCI pathway shall be assigned a maximum allowable credit value, equal to 75% of capital expenditures minus grant revenue.

(a) Capital expenditures shall be taken from Line 1 of subpart (6) (B), above.

(b) Grant revenue shall be taken from Line 5 of subpart (6) (B), above, less any grant revenue specifically awarded for non-capital expenses, such as operations and maintenance.

(B) The Executive Officer shall track the cumulative credit value generated by each station that generates HRI/FCI credits, as the sum of all quarterly credit values in constant-dollar terms using the Consumer Price Index as the discount rate. Quarterly credit value, for the purpose of this determination, shall be calculated by multiplying the number of credits assigned in a given quarter by the average LCFS credit price reported to CARB in that quarter.[11]

[11] Note that this valuation does not imply that the credits must actually be sold at that price, nor that their use by the credit generator is restricted in any way. The cumulative credit value is only a metric for tracking total infrastructure capacity credit value as compared to capital expenditure.

(C) When a station's cumulative credit value exceeds the maximum allowable credit value, it is no longer eligible for HRI/FCI credits. This loss of eligibility for HRI or FCI credits shall not otherwise affect the station's status in the LCFS or any other grant program, regulation or market-based mechanism. In the quarter in which a station loses its eligibility for HRI/FCI credits, the Executive Officer shall issue credits until that station's maximum allowable credit value is reached.

(D) Stations which are approved for an expanded capacity, as in subpart (7), above, may elect to recalculate their maximum allowable credit value based on the total capital cost and grant value of the total project.

These amendments ensure that the proposed HRI and FCI pathways achieve their intent of supporting the deployment of ZEV fueling infrastructure while ensuring that fuel providers do not make windfall profits from a State climate policy instrument. Requiring the developer to retain 25% exposure to the capital involved in a project ensures that an incentive remains to site and size stations appropriately for expected future demand, rather than to maximize near-term payback from HRI and FCI credits.

It should be noted that eligibility for HRI and/or FCI credits in no way affects a station's eligibility for credits through conventional LCFS pathways or participation in other programs. Revenue from LCFS credits, the sale of fuels and all other sources is still due to the station owner.

Rationale for the suggested Amendment:

As written, the HRI and FCI pathways could yield far more revenue from the sale of HRI and FCI credits than is necessary to shield project developers from excessive risk from building fueling infrastructure in advance of vehicle deployment.

Consider a hypothetical 1200 kg/day hydrogen fueling station approved for a HRI pathway, which enters service in 2020, which is available for use 98% of the specified hours and dispenses an average of 400 kg of hydrogen per weekday and half as much on weekends[12]. Using the default CI specified in the Modified Text for the dispensed hydrogen, this station would generate over 1400 HRI credits per quarter in 2020.[13] This yields over $700,000 of yearly revenue at $125 LCFS credit prices.[14] If this station's dispensed hydrogen grows to 800 kg per weekday by 2025, *the total HRI credit generation will be over $3 million through 2025.* Note that this growth trajectory for hydrogen consumption is extremely optimistic. 400 kg/day is several times the likely hydrogen demand from most stations as predicted by the CARB Illustrative Compliance Scenario Calculator and significantly in excess of IEPR projections in 2020. Doubling per-station hydrogen consumption in just 5 years would imply a nearly unprecedented rate of growth. More likely hydrogen growth trajectories would yield even more HRI credits and exacerbate the degree by which HRI credits overshoot capital costs.

[12] To provide a sense of scale for the hypothetical 300 kg/day station: The CARB Illustrative Compliance Scenario anticipates approximately 2.5 million kg of total hydrogen demand in 2020, which equates to approximately 110 kg per station per day if the 2020 fleet is comprised of the approximately 60 currently operational stations plus all stations for which the CEC ARFVTP program has secured funding. If hydrogen demand follows the significantly higher utilization trajectory projected under the 2017 IEPR, distributed across 75 stations, each station would average around 340 kg per day. As each station sells more hydrogen, the number of HRI credits decreases.

[13] This calculation was confirmed by Jim Duffy in an email on June 28th.

[14] See attached modeling memo and worksheet.

2013 NREL hydrogen fueling infrastructure cost projections place the capital cost for a 1200 kg station in a range between $4 million and $6.2 million[15]; these values would be expected to decline as more stations are constructed and operators gain more experience with their construction and operation. Most station developers indicate that the overwhelming majority of stations deployed over the next 5 years in California will also be supported by Federal, State or local grants, such as the CEC ARFVTP program, which has invested over $130 million in hydrogen fueling infrastructure through the 2018-2019 fiscal year, supporting the deployment of 64 fueling stations.[16] These grants typically provide a maximum of half the total capital cost of a project, in order to maximize the number of stations deployed and to ensure that project developers retain some risk, as an incentive to commit to expanding the utilization of each station once deployed. **The proposed HRI credits, in combination with other policy incentives will likely exceed the capital costs of expected hydrogen fueling infrastructure.**

[15] Based on values presented in Table ES-1. https://www.nrel.gov/docs/fy13osti/56412.pdf

[16] https://efiling.energy.ca.gov/GetDocument.aspx?tn=223279, Table ES-1

Similarly, the per-station incentive for FCI appears to be significantly in excess of what is needed to stimulate deployment of DC Fast Chargers. Navigant Consulting estimates capital costs for a 150 kW charger to be $50,000 - $75,000.[17] Both the CARB case and the Cerulogy case in the attached model predict a 150 kW charger installed in 2020 would receive $153,000 or $134,000 respectively, through 2025; potentially more than double the capital cost for installing the infrastructure, especially where the site has been made ready for charger installation. The California Public Utilities Commission recently approved over $730 million in charging infrastructure investments, much of which will be used to make sites ready for charger installation. This means that there will likely be a great many opportunities for installing chargers at the lower end of the projected cost range. The proposed FCI pathway does not differentiate between high-cost and low cost sites when allocating FCI credits, our proposed amendments do.

[17] Costs for DCFC installation vary significantly due to differing needs for site preparation and enhancements to local grid infrastructure.

The credit generation model presented in the Modified Text places no limits on the total amount of credit which could be generated by any given station and the modeling shown on the attached worksheet, and described in the modeling memo, demonstrate that under feasible conditions, **the revenue provided from HRI and FCI credits could exceed the total capital cost of each station.** While we acknowledge that state policies can, and should, have a role in supporting the deployment of ZEV fueling infrastructure, State policy instruments, especially ones which function through a market-based mechanism, should not guarantee profit. As structured in the Modified Text, the HRI and FCI pathways could easily guarantee profits regardless of the station's utilization or its contribution to attaining California's ZEV deployment goals. This profit could easily be well in excess of any reasonable rate of return allowed under any other State grant or incentive program.

The proposed amendments ensure that the HRI and FCI pathways fulfil their intended function of supporting the deployment of ZEV fueling infrastructure, while eliminating the risk of windfall profits from this provision. By limiting total state capital incentives to 75% of total capital required, project developers are obligated to carefully consider future demand for a proposed station and build to meet expected need, rather than building to maximize credit under the HRI and FCI pathways. Without some skin in the game, developers could find that capacity up to the program's limit will always pay for itself through HRI and FCI credits, regardless of whether it is ever used. Should the HRI and FCI programs routinely run up against their ceiling values, as the our modeling indicates is likely, a limitation on credits generated per station will also ensure that these provisions support the largest possible number of stations, instead of simply rewarding the first developers to get an approved application.

The Proposed HRI and FCI Pathways Create a Strong Incentive to Over-size Fueling Infrastructure Compared to Expected Need

Since the capacity of proposed fueling infrastructure is directly proportional to HRI and FCI credits generated under most conditions, the program creates an incentive for

project developers to install more capacity than expected demand at a given location could reasonably support. To some extent, this is a desired outcome since state ZEV deployment goals are better served by maintaining a reasonable buffer of excess capacity than by insufficiency. There is a limit to this benefit, however, at at some point excess capacity becomes merely excessive.

The figure to the right illustrates the relationship between station size and expected HRI credit generation. For both the BAU and Success cases, a 1200 kg/day station yields approximately $2.8 million more in HRI revenue through 2025 than a 600 kg/day station. From a producer's point of view, if the incremental cost to increase the size of a proposed station from 600 kg/day to 1200 kg/day is less than $2.8 million, it becomes an extremely attractive proposition. This may lead to stations significantly over-sized for the site's needs, with the expense of unnecessary capacity borne by California fuel consumers, and communities who breathe dirtier air as fewer clean fuels make it into the market.

Total incentive per station 2020-2025 ($ million)

	Case	
Station Capacity (kg)	**BAU**	**Success**
1200	$ 4.8	$ 3.4
1000	$ 3.9	$ 2.4
800	$ 2.9	$ 1.5
600	$ 2.0	$ 0.5

Limiting maximum credit generation per station helps ensure that Californians do not pay for capacity that benefits no one except the station's operator. (NEXTGEN3_FF65-9)

Agency Response: Staff appreciates the thorough review of the HRI and FCI provisions, but disagrees with several of the points raised by the commenter.

Staff disagrees that the proposed infrastructure provisions will significantly upset the credit market. In response to public comment, staff instituted a hard cap of 2.5 percent of overall program deficits, for HRI and FCI credit generation. Even if HRI and FCI credit generation reach the maximum of 2.5 percent each of overall program deficits, which is not guaranteed, staff is confident that the hard cap will prevent the infrastructure crediting provisions from upsetting the credit market and significantly reducing overall revenue for entities reporting alternative fuels. As presented in the revised Illustrative Compliance Scenario calculator, staff expects credit prices to remain above $85 through 2030, even with the inclusion of infrastructure credits. Please see also Response I-17.8 in Chapter V regarding the impact of infrastructure crediting on the overall credit market. In addition, although the commenter is correct in citing Dr. Sperling when he suggested that the infrastructure provisions would constitute roughly 1 to 2 percent of total deficits, which staff has taken to mean 1 to 2 percent each for

HRI and FCI charging, staff received strong support from the Board for proposing that HRI and FCI crediting be capped at 2.5 percent each of total deficits at the second Board Hearing. Staff's calculations show that limiting HRI and FCI crediting to 1 percent of deficits would not be sufficient to help support the buildout of 200 hydrogen stations and 10,000 DC fast chargers.

As mentioned above, staff did not adopt either of the methodologies suggested by the commenter for limiting total HRI and FCI credits, but instead adopted a methodology that sets a hard cap by ceasing to approve applications when the forecasted crediting has exceeded the maximum permitted quantity in a given quarter. Apportioning credits across all approved stations, whether uniformly or based on date approved in the program, would unnecessarily complicate the crediting process and would undermine the program's goal of encouraging investment in ZEV infrastructure by introducing uncertainty regarding quarterly revenue from these provisions. Please see Response I-11.3 in this chapter for a description of the methodology staff will use to maintain the 2.5 percent cap on quarterly HRI and FCI infrastructure credits.

Staff acknowledges that credit revenue from the HRI and FCI provisions may be significant for FSE participating in the program. However, staff believes that the commenter has over-estimated the revenue that each FSE may generate. For the purposes of this response, staff will highlight a few of the issues found in the calculations and assumptions contained in the model formally submitted by the commenter:

- For HRI calculations, the commenter assumes that California Energy Commission (CEC) grant funding will cover 50 percent of the capital costs of hydrogen stations. Staff disagrees with this assertion. We assume that CEC grant funding under AB 8 will amount to approximately $110 million over the next six years and that that amount will need to help support at least 140 additional hydrogen stations if the State is to meet the Executive Order goal of 200 stations by 2025. Assuming each station costs approximately $4 million, CEC grant funding will cover an average of approximately 20 percent of capital costs.
- For both the HRI and FCI calculations, the commenter does not include a discount rate when calculating the value of total revenue in future years, thus over-estimating the present value of HRI and FCI credit revenue. Present value of future revenue must be used when comparing to upfront capital cost expenditures.
- For both the HRI and FCI calculations, calculations for total revenue per FSE in most scenarios assume that the cap on total infrastructure credits is exceeded. With the introduction of a hard cap on total infrastructure credits, the revenue per FSE will be much lower than estimated by the commenter, thus limiting the overall program impact.

The commenter states that the infrastructure provisions will guarantee a profit for ZEV infrastructure. Staff disagrees with this assertion. Internal modeling has shown that per-FSE revenue from these provisions is highly dependent on a number of factors, including the likelihood of receiving a CEC grant, volatility in credit price, and more. In several low credit price scenarios, FSE do not break even after accounting for both capital and operational costs associated with the site.

However, in response to stakeholder comments, staff limited total FCI revenue per FSE to the total capital costs of the FSE minus any grant funding. Please see Response I-2.4, Removal of cap on HRI credits per Station, in Chapter VI for staff's rationale for limiting FCI revenue to capital costs but not HRI revenue.

Staff has attempted to create provisions that comply with Executive Order B-48-18 by using the LCFS to incentivize buildout of 200 hydrogen stations and 10,000 DC fast chargers by 2025. Meeting these ambitious targets requires that investment occur in advance of fuel demand and that the station be sustainable until throughput can increase with increased ZEV penetration. Although staff acknowledges that the provisions may be generous in some circumstances, staff believes that the provision meets the intent of Executive Order B-48-18 and the Board's direction.

Lastly, the commenter suggests that the infrastructure provisions incentivize over-building of stations. While credit generation potential does increase with the capacity of each FSE, staff disagrees that the program as designed will result in unreasonable over-building. Please see Response I-2.4, Removal of cap on HRI credits per Station, in Chapter VI for a description of staff's efforts to protect against this phenomenon for HRI crediting. In addition, DC fast chargers are limited to revenue generation equal to or below the total capital cost of the FSE (minus any grant funding), which is not guaranteed to occur during the 5-year crediting window. Further, the credit calculation for DC fast chargers does not scale linearly with increased charging capacity, in an effort to prevent placement of unreasonable power ratings.

Finally, the amendments require complete reporting of all costs and revenues for hydrogen stations and fast chargers supported by the infrastructure provision. As directed in Board Resolution 18-34, staff will continue to monitor the performance of the HRI and FCI crediting provisions and will be reporting back to the Board every year on the status of LCFS implementation. Staff will have the opportunity to make adjustments to these provisions if necessary in a future rulemaking, and will utilize the reporting and recordkeeping requirements included in section 95486.2 to gain an accurate understanding of the effectiveness of these provisions.

I-7. *Ongoing Review of Program Performance*

I-7.1. Multiple Comments: *Monitoring of Program Performance*

Comment: Application Period for Eligibility: we encourage the ARB staff to complete the planned "evaluation to determine whether HRI application eligibility should be extended beyond 2025" well in advance of the stated objective for "prior to 2026" in order to provide certainty and stability to the market. (H2IND2_FF17-3)

Comment: Completing well in advance of 2026 the planned evaluation to determine whether HRI application eligibility should be extended beyond 2025 would provide certainty and stability to the market. (SHELL2_FF57-3)

> **Agency Response:** Staff will be monitoring station development as a result of this program and reviewing the information submitted pursuant to section 95486.2(a)(6). Staff will complete the evaluation of potential extension of the HRI provision before 2026 as stated, but will take into consideration the market benefits of providing early notice for programmatic decisions.

I-7.2. *Economic Impact of Infrastructure Credits*

Comment: The economic impact of infrastructure credits should be reviewed in two years

One very basic concern we have is whether the level of support implied by granting LCFS credits for unused infrastructures is appropriate. Too low a level of support would be ineffective at substantially speeding transportation electrification, but too high a level of support could encourage poor decision making about infrastructure deployment. If a hydrogen station or DC fast charging operator can obtain a secure return on investment without substantial utilization, then they may build infrastructure where it is convenient and inexpensive to build, rather than where it will be most valuable to accelerate transportation electrification. There are probably some locations for infrastructure that would assist transportation electrification despite ongoing low utilization, but the LCFS infrastructure credit is a poor way to support these stations, since the LCFS has no mechanism to distinguish high value low utilization stations from low value low utilization stations. Other support mechanisms in which more discretion is available to program administrators would be a more appropriate means to support high value, low utilization infrastructure. The LCFS infrastructure crediting mechanism should focus on making stations more economically attractive in general, to accelerate the build out of ZEV infrastructure. (UCS3_FF28-5)

> **Agency Response:** Staff agrees that the infrastructure provisions should not be used to intentionally fund stations in sub-optimal locations. For this reason, staff added a requirement in section 95486.2(a)(2)(J) that the applicant must justify the proposed station location and how the location contributes to the hydrogen fueling network. The Executive Officer will have discretion to make judgements on the justification of a proposed station, which affords a level of protection to avoid capacity crediting that does not contribute to the goals of this provision.

Staff also agrees that monitoring the economics of the incentive is warranted. Staff has proposed the reporting of sufficient cost and revenue data for all hydrogen stations and DCFCs, so that CARB can monitor the economics of the provision and make adjustments during future rulemakings, if necessary.

I-7.3. Multiple Comments: *Ongoing Review of Program Performance*

Comment: CARB has several levers that can be used to increase or decrease the value of the support the LCFS offers to ZEV infrastructure, including the number of years infrastructure is eligible, the number of hours per day that constitute full utilization, and whether there is a declining cap on credits for underused infrastructure. The material presented in the workshop and our own knowledge are insufficient to assess whether CARB has struck the right balance. We urge CARB to continue to analyze how LCFS infrastructure credits interact with other sources of support and the basic economics of the ZEV fueling infrastructure after the program has been operational for two years and to make appropriate adjustments to the program based on their findings. (UCS3_FF28-6)

Comment: Given that it is a significant departure from the traditional LCFS crediting program however, PG&E recommends that ARB and stakeholders carefully monitor the effects of these new capacity crediting programs on the overall LCFS market. (PGE2_FF64-3)

Agency Response: Staff is committed to ongoing performance review of the program and to the review of applications and records submitted by applicants, and has the ability to make program adjustments as needed during future formal rulemakings.

I-7.4. *Provisions should be a Pilot Program*

Comment: 3. ARB should make these provisions a “pilot” and add an earlier review to evaluate the efficacy and impact of the HCI and FCI provisions.

Because of the fast turn-around since the April 27th Board hearing to further develop these provisions, NRDC recommends that staff make the HCI and FCI provisions part of a 2-year pilot, after which ARB will workshop the provisions to evaluate questions around the effectiveness of the provisions, the impacts on projects, and the impacts on the overall program. As demonstrated in Attachment F “Public Workshop Materials” for the June 11th, 2018 workshop there is large potential uncertainty in the effects of these provisions on specific projects. (NRDC3_FF49-4)

Agency Response: Staff did not propose that the HRI and FCI provisions be part of a pilot program. Staff did not believe a pilot program would provide sufficient regulatory certainty to incentivize infrastructure development. However, staff will evaluate the program’s performance and efficacy on an ongoing basis to inform future programmatic decisions regarding these provisions, as directed in Board Resolution 18-34: “Be it further resolved that the Board directs the Executive Officer to monitor development of the ZEV Fueling Infrastructure

credits under the Low Carbon Fuel Standard, including how these credits impact the business case for such projects, and to propose technical updates as needed."

I-8. *Capacity Calculation for Hydrogen Stations*

I-8.1. Multiple Comments: *Capacity Determination for Hydrogen Station for HRI Crediting*

Comment: Design Nameplate Capacity: we encourage the use of a 24-hour period, according to an established fueling profile, to determine the Design Nameplate Capacity as this will better align the incentive for station design created by the HRI to serving customer demand. For comparison, only approximately 78% of demand is served in a 12-hour period from 0600 to 1800 hours. (H2IND2_FF17-4)

Comment: Using an eighteen-hour (18-hour) period, from 0500 to 2300, or 24-hour period according to an established typical fueling profile to determine Design Nameplate Capacity would better align with serving customer demand. (SHELL2_FF57-4)

Comment: FirstElement recommends that HRI credits be given on the basis of 24-hour capacity that accounts for typical customer fueling profiles. Based on data collected by the California Energy Commission of consumer refueling patterns, retail hydrogen refueling very closely mirrors gasoline refueling behavior based on publicly accessible data provided in a study by Chevron. Based on those data, the capacity of a station can be based on a 24-hour timeframe, with the following requirements to account for typical refueling profiles:

i. Over a 24 hour period station must be able to dispense 100% of its rated capacity
ii. Over an 18 hour period station must be able to dispense 95% of its rated capacity
iii. Over a 12 hour period station must be able to dispense 75% of its rated capacity
iv. In a single peak hour (typically 6-7 pm), station should be able to dispense 7% of its rated capacity

FirstElement believes that the program should be built around a capacity timeframe that reflects real consumer usage patterns, because it will best serve to incentivize station developers to install hydrogen stations that best meet consumer needs. (FEF1_FF71-3)

Agency Response: Staff agrees with the stakeholder recommendation to use a 24-hour capacity based on an established fueling profile. As part of 2nd 15-day modifications, staff proposed to use the HySCapE 1.0 model (or equivalent model or approved capacity estimation methodology) to calculate station nameplate refueling capacity. In response to stakeholder comments, the HySCapE model uses a 24-hour capacity based upon an established fueling

profile. Staff believes this profile is representative of typical station demand. Staff did not propose to require the specific dispensing capabilities listed in FEF1_FF71-3 to maintain the simplicity of the program and to avoid unnecessary verification burden.

I-8.2. Multiple Comments: *15-Year Crediting Period and Declining Cap on Hydrogen Capacity*

Comment: Include a declining cap on credits for unutilized infrastructure

The number of credits provided for low utilization infrastructure should decline over time. We recommend that the maximum unused capacity credited decline by 5% a year for the hydrogen station provisions and by 10% per year for the DC fast chargers. The materials presented in the workshop reflect an assumption that utilization of ZEV refueling infrastructure would increase over time, with support steadily shifting from infrastructure-based credits to credits based on delivered fuel. Indeed, this assumption is embedded in the calculations of subsidy value and economics. However, as written, there is no requirement that infrastructure credits decline over time, and it is possible that a facility could draw credits based on its full capacity for the relevant timeframe (15 years for hydrogen and 5 for DC fast charging) while dispensing no fuel at all to customers during that time. A station whose economic viability depends principally on drawing infrastructure credits is a poor use of program support and is unlikely to survive once infrastructure support has ended. A declining cap on eligibility would provide early infrastructure support while still ensuring that fuel station operators have an incentive to attract customers. In aligning the incentives, the program will gradually shift stations from support for infrastructure to support for clean fuels dispensed and, ultimately, to a viable business model without ongoing policy support. (UCS3_FF28-4)

Comment: However, once we account for a few additional real costs as well as the realities of a fledgling FCEV market, FirstElement believes that a declining capacity credit that is front-loaded, rather than a constant capacity credit over the program's 15-year per station period will be more effective to address early market challenges and achieve the shared goals of this program. Namely, the declining (vs constant) capacity credit helps address two of the most significant challenges facing retail hydrogen stations:

a) Achieving lower price at the pump and funding growth are more difficult during earlier years of fuel cell vehicle market growth. A declining credit is front-loaded to help offset these early stage challenges.

b) Station developers will be more motivated to sell hydrogen over time because revenues from capacity credits will decline. This will motivate developers to select locations that reach more consumers, and to provide a better customer experience (including a lower price at the pump).

c) A declining capacity credit helps achieve lower price at the pump (even during the initial years of operating a station) and a reasonable IRRs simultaneously. (FEF1_FF71-5)

Agency Response: Staff proposed not to include a declining cap on infrastructure credit generation. Economic modeling by staff showed that a declining cap would have little effect on the overall return on investment, because the cap would have the greatest impact in the latter crediting years, which results in a correspondingly small effect on net present value. In addition, adding a declining cap would have added an unnecessary level of complexity to these provisions, especially when evaluating requests for station capacity expansions.

I-9. *Requirements to Generate HRI Credits*

I-9.1. Comment: OEM station approval: we recommend modifying the requirement that "[a]t least three OEM shave confirmed that the station meets protocol expectations, and their customer can fuel at the station" (Sec. 95486.2(a)(4)(D)) to require that the station fueling interface shall conform to SAE International J2601: 2016, Fueling Protocols for Light Duty Gaseous Hydrogen Surface Vehicles (www.sae.org), or the most recent version of the standard published and promulgated by the SAE. The fueling interface shall be tested per CSA HGV 4.3: 2012, Test Methods for Hydrogen Fueling Parameter Evaluation and related devices, or the most recent published version of the standard, and confirmed by either (1) a 3rd party Nationally Recognized Test Lab (NRTL) as approved by CARB, or (2) the U.S. Department of Energy Hydrogen Station Equipment Performance (HyStEP) device as practicable, for fueling interface confirmation. (H2IND2_FF17-5)

Agency Response: The final text includes the requirement that at least three OEMs have confirmed that the station meets protocol expectations and their customers can fuel at the station for consistency with requirements for infrastructure grants issued by the California Energy Commission.

I-9.2. Comment: Deadline to Open: as drafted, the regulation requires that "a station must be operational within 24 months of application approval." (Sec. 95486.2(a)(4)(F).) We believe this deadline is an appropriate requirement to develop approved stations, but suggest that it should not result in a forfeiture of HRI credits when delays are caused by permitting agencies and not by the applicant. Permitting delays that exceed 30 days should be excluded from the 24-month period. (H2IND2_FF17-8)

Agency Response: Staff proposed not to remove the automatic cancellation HRI applications if the station is not operational within 24 months of application approval. This requirement encourages station developers to build their stations more quickly, providing the appropriate signals to automakers and prospective hydrogen vehicle owners. Staff believes that 24 months is sufficient time to bring a station to operational status.

I-10. *Requirements to Generate FCI Credits*

I-10.1. Multiple Comments: *Certification by County Departments of Weights and Measures*

Comment: h) CalETC requests deletion of the requirements on DC fast chargers to be certified by county weights and measures at this time. CalETC believes this requirement can be added in future rulemakings after the state adopts the certification standards and when the counties are trained and ready. (CALETC3_FF60-7h)

Comment: *Subsection (b)(4)(F):* SMUD has concerns with the requirement to have County Departments of Weights and Measures verify charging unit performance to enable the FSE to sell electricity by the kWh. SMUD does not question the need to have the charging unit performance verified. However, the California Department of Agriculture Division of Measurement standards has not completed the standards development on this topic for implementation by counties for the purpose of certifying public charger energy delivery standards for consumer protection. Thus, it is not possible to comply with the requirement at the present time, and it may take years before county sealers of weights and measures are empowered to enforce the requirement. Accordingly, SMUD requests that ARB wait to implement this requirement until the state adopts the certification standards and the counties are trained and ready to implement them. (SMUD2_FF63-9)

Comment: f. remove the charging unit performance verification requirement, as this issue is being addressed by the Division of Measurements and Standards in a separate rulemaking.

…

VI. Remove the charging unit performance verification requirement, as this issue is being addressed by the Division of Measurements and Standards (DMS) in a separate rulemaking.

In 2016, the California DMS began a pre-rulemaking process to develop regulatory language for EV charging stations requirements.[10] This effort is complemented by the National Institute of Standards and Technology's (NIST) continued updates to Handbook 44, Section 3.4 for EV fueling systems at the national level.[11] However, the DMS effort is still in the pre-rulemaking stage, and stakeholders have not received updated draft regulatory language. Therefore, it is premature to make an explicit reference to regulatory language that has not been finalized. Once the DMS process is finalized and regulatory language has been adopted, this requirement can be retroactively referenced in the context of LCFS.

[10] https://www.cdfa.ca.gov/dms/pdfs/regulations/EVSE_Pre_Rule_Wkshop_Presentation_8-17-2016.pdf
[11] https://www.nist.gov/pml/weights-and-measures/nist-handbook-44-2018-current-edition

If staff believes the proposed language regarding weights and measures must be included, we recommend modifying the text to say: "The County Department of Weights and Measures is in the process of establishing standards for verifying charging

unit performance to enable a FSE to sell electricity by kWh. Once these requirements are adopted in state code, they will also apply to the FCI pathway." (TESLA2_FF69-6)

Comment: Similarly, we respectfully request that CARB remove the charging unit performance verification requirement, as this issue is being addressed by the Division of Measurements and Standards in a separate rulemaking. (EVGO1_FF62-4)

> **Agency Response:** In response to stakeholder feedback, staff proposed to remove the provision that the County Departments of Weights and Measures has verified charging unit performance.

I-11. *Overall Cap on Infrastructure Credits*

I-11.1. Multiple Comments: *Cap HRI Credits at 3.5 Percent*

Comment: Maximum quantity of infrastructure credits: we encourage setting the **limit for HRI at 3.5 percent of overall program deficits**, and suggest ARB staff provide analysis and forecast well in advance of reaching this cap, to provide certainty and stability to the market. The generation of HRI credits will result from the successful development of hydrogen refueling infrastructure and the decarbonization of the hydrogen supply. Setting the maximum quantity of HRI credits at 3.5 percent will give appropriate running room to enable this success case without undue impact on the overall LCFS policy. Setting the maximum number of HRI credits at 2.5 percent of program deficits may unduly restrict the HRI pathway if the LCFS is successful in catalyzing the development of low-carbon fuels and therefore generates fewer deficits. (H2IND2_FF17-9)

Comment: Allowing a maximum quantity of HRI Pathway credits of three and a half percent (3.5%) of overall program deficits would give appropriate running room to enable success with hydrogen infrastructure and supply decarbonization without undue adverse impact to the overall LCFS policy. (SHELL2_FF57-7)

> **Agency Response:** Staff proposed to maintain the originally-proposed provision that HRI and FCI credits may only generate up to 2.5 percent each of total deficits from the prior quarter. The reason for not increasing this percentage is two-fold: 1) At the April 27, 2018 Board Hearing, the Board stated that this provision should be kept to a limited quantity of credits, preferably close to 1 to 2 percent of prior deficits, and 2) Staff's station modeling suggests that a cap at 2.5 percent would provide considerable assistance to meet the Governor's goal of 200 hydrogen stations and 10,000 DCFC by 2025 in Executive Order B-48-18. In addition, staff is committed to ongoing review of the HRI provisions and will continue to engage with stakeholders if program adjustments are needed.

I-11.2. Comment: g) CalETC supports the concept of limiting DC fast charger credits to 2.5 percent of all deficits but is concerned that this also encourages a slow start to the program, 2.5 percent of deficits in the early years is much less than in the later years (e.g., 2023-2025). To encourage a faster start to the program, CalETC requests amendments that would allow the 2.5 percent cap to cover an average for all seven

years (2019-2025) and allow up to 3.5 percent of deficits each year in the early years (e.g., 2019-2022). (CALETC3_FF60-7g)

> **Agency Response:** Please see Response I-11.1 in Chapter V. Staff disagrees with the suggestion that 2.5 percent of deficits in the early years is much less than in the later years and that this will result in a slow start to the program. Staff's modeling of illustrative compliance scenarios for the rulemaking shows that total deficits in 2019 are almost 60 percent of those in the year 2025 and total deficits in 2021 are over 80 percent of those in 2025. Therefore, staff does not believe that the additional complexity that would be necessary to implement the commenter's recommendation is warranted.

I-11.3. Comment: 1. Staff should modify the provisions to place a hard-cap on infrastructure capacity credits

NRDC appreciates staff's attempts to put percentage-limits and a sunset to the HRI and FCI provisions, and to also restrict the eligibility to only projects not receiving settlement funds (e.g. Volkswagen Settlement among others). However, staff's proposal to provide a 2.5% limit to the HRI and another 2.5% limit to the FCI credits (for a supposed limit of 5%) is actually a soft cap. The current proposal only restricts ARB from approving additional applications once the credits make up 2.5% of the quarterly deficit (or requirement). It is very likely that between the time ARB has approved the initial group of HRI and FCI projects, to the time that the initial HRI and FCI projects are built and generating the 2.5% of the credits, an entire pipeline of projects exceeding the 2.5% may have already been approved.

We ask that the current soft-limit structure proposed by staff be converted into a hard cap, based on the ***cumulative approved*** HRI and FCI projects and capacity relative to the actual deficits for that specific year. A first-come, first serve approach could be used, whereby a project application could be approved until the cumulative total of approved projects reaches the 2.5% threshold relative to the current quarter. To account for some projects not moving forward, a time-limit for project developers to build and commission stations could be instituted, such that they would need to go back into the end of the queue for their application so that other projects could move forward.

Absent a hard cap, the impact of these provisions could greatly exceed the 5% overall impact, meaning less actual, overall GHG emission reductions will be achieved. (NRDC3_FF49-2)

> **Agency Response:** Staff recognized the potential for overshooting the 5 percent overall impact with a soft cap in place, and proposed a hard cap of HRI and FCI credits at 2.5 percent each of overall deficit generation from the prior quarter as part of the 2nd 15-day modifications. Staff will use the equations proposed in sections 95486.2(a)(3)(A) and 95486.2(b)(3)(A) to estimate the potential HRI or FCI credits for comparison to overall deficit generation in the prior quarter. Applications will be evaluated on a first-come, first-served basis

and will only be approved when HRI or FCI credits are less than 2.5 percent of deficits.

I-11.4. Comment: The Board also instructed the Executive Officer to develop a process to grant LCFS credits to hydrogen stations and DC fast chargers based on their capacity, in addition to credits received for fuel dispensed. While UCS opposed granting LCFS credits based on unused infrastructure capacity, we recognize the importance of infrastructure and are sympathetic to the Board's desire to ensure that infrastructure limitations do not impede the deployment of ZEVs. It is important that this deviation from the overall fuel neutrality of the LCFS is constrained in time, is limited in the extent to which it dilutes the rest of the program, and does not get extended to other fuels. It would not be appropriate to extend the same treatment to other fuels that do not provide the same health and other co-benefits that ZEVs offer. We also have two specific recommendations, which we describe below. (UCS3_FF28-3)

> **Agency Response:** Staff proposed that applications for infrastructure crediting will not be accepted after December 31, 2025, and set 15- and 5-year crediting periods for HRI and FCI credits, respectively. To limit the effect on the overall credit market, staff proposed a hard cap on total HRI and FCI credits generated in any given quarter. This was set at 2.5 percent of total deficits from the prior quarter. Regarding the rationale for limiting infrastructure crediting to zero emission technologies, please see Response I-3.1, Departure from Fuel Neutral Approach and would not Represent Actual GHG Emission Reductions, in this chapter.

I-12. *Reporting and Recordkeeping Requirements*

I-12.1. Multiple Comments: *Reporting Costs and Revenues*

Comment: Reporting and Recordkeeping Requirements: we strongly encourage removing the requirement to report "station costs and revenues" as this will cause commercial difficulty for station developers and operators in contracting activities, will inhibit private investment, and is not needed for ARB's administration of the program. The referenced "intended goals of reducing station costs and the retail price of dispensed hydrogen over time" can be observed in the marketplace and through other existing reporting structures like the ARFVTP program. (H2IND2_FF17-10)

Comment: Removing the requirement to report station costs and revenues would avoid commercial difficulty in contracting activities that would inhibit private investment and diminish the efficacy of the HRI Pathway. (SHELL2_FF57-8)

> **Agency Response:** While staff understands the concerns expressed by the commenters, staff proposed to keep the requirement to report station costs and revenues (summarized in section 95486.2(a)(6)). This information is critical for ongoing performance evaluation of the infrastructure provisions, and will be instrumental in future policy decisions regarding the structure and life of the provisions. This requirement also ensures that the data is coming directly to

staff, rather than to another agency which may be reluctant to share cost data. All cost data submitted to CARB will be maintained as Confidential Business Information and will only be shared in an aggregated form that protects the identity and data of individual station owners.

I-13. *Crediting Period*

Comment: 2. The HCI and FCI crediting provisions should be sunset after 5-8 years for a project and include a phase-down of credits for unutilized capacity.

We recognize the HCI and FCI provisions is intended to provide enough value over a period to overcome potential low, initial utilization. However, a full 15-year crediting arrangement for the HCI would provide significant credits, potentially well beyond the 2030 time-period, suggesting an overly generous amount of multiplier credits over the lifetime of a project as opposed to just the initial period.

Second, the credits remain largely fixed over time, even if the HCI and FCI project developers or operators do not increase utilization rates, setting up a perverse incentive where if the project developer increases utilization there would be a reduced HCI and FCI incentive. A station operator may have less incentive to attractively price the refueling service or fuel since "unused" capacity is still being rewarded. ARB should solve this by adding a factor in the HCI and FCI crediting equations to simply reduce the HCI and FCI credits for unutilized capacity over time. (NRDC3_FF49-3)

> **Agency Response:** Staff anticipates that throughput will increase over the crediting period as the number of ZEVs increases, resulting in a "self-sunsetting" incentive. Moreover, actual dispensed hydrogen or electricity generates revenue from the fuel retail markup in addition to the LCFS credit value and, therefore, station owners are incented to sell fuel rather than simply rely on capacity credits as revenue. Staff also proposed to require justification of station location and capacity for HRI applications, providing another level of discretion to avoid buildout of stations in inappropriate applications, and subsequent over-crediting. Regarding staff's rationale for not including a declining cap on capacity crediting, please see Response I-8.2 in this chapter.

I-14. *Capacity Calculation for DCFC*

I-14.1. Multiple Comments: *Capacity Determination for DCFC Stations*

Comment: CalETC believes there is not a large difference in cap_ex cost between 50 kW and 150 kW DC fast chargers. That is why we do not support the provision in the 15-day modifications that would provide 3 times more capacity credits to a 150 kW DC fast charger than a 50 kW one. Specifically, CalETC suggests the 15-day modification's formula for DC fast charge capacity credits be changed to be more cost-based for chargers between 50 and 150 kW (e.g., allowing about 25-50 percent more capacity credits to a 150 kW DC fast charger than a 50 kW one). (CALETC3_FF60-7a)

Comment: c. Reduce the hours-per-day crediting to ensure credits are effectively deployed to maximize the total number of chargers supported by this pathway;

…

III. Reduce the hours-per-day crediting to ensure credits are effectively deployed to maximize the total number of chargers supported by this pathway

Reducing the crediting assumption not only encourages developers to be more cost-efficient but also ensures the credits available under the pathway funds as many chargers to reach the Governor's goal. The proposed formula for calculating FCI credits is currently six hours per day for all charger capacities. The estimated credit value generated based on six hours per day would equate to ~90% of the estimated capex cost for a 50kW charger.[7] We recommend reducing max crediting to five hours per day for a 50kW charger, which would increase the required investment from the developer from ~10% to ~27% and incentivize the developer to ensure the long-term success of the charger.

[7] Assumes $125 credit pricing and $60,000 capex cost for an average 50kW charger in California.

Higher power rating chargers should also not be over-incentivized relative to lower power rating chargers. Under the current crediting formula, a charger with a simultaneous power rating of 150kW receives three times as many credits as a 50kW charger when all other factors are equal. However, the capex cost for a 150kW charger does not equal three times the cost of a 50kW charger. As a result, the estimated credit value generated based on six hours per day would equate to ~200% of the estimated capex cost of a 150kW charger, which incentivizes developers to overbuild for charger capacity.[8]

[8] Assumes $125 credit pricing and $80,000 capex cost for an average 150kW charger in California.

CARB can use a scale factor to reduce the daily crediting for higher capacity chargers so the estimated cost recovery is within the same range as the cost recovery for a 50kW charger at five hours per day of crediting. For example, applying a scale factor that reduces the crediting for a 150kW charger (maximum power rating allowed for crediting under the pathway) to 2.39 hours per day would result in a similar level of investment required for a 50kW charger based on 5 hours per day of crediting (see table below for potential hours of crediting for different charger capacities). This type of dynamic crediting would ensure developers install chargers with the appropriate power rating at a site as opposed to installing chargers with the highest power rating in order to maximize credit generation.

Scenarios for Different Charger Capacities[9]

Charger Capacity	Current Crediting Assumption / Credit Generation	Dynamic Crediting Assumption / Credit Generation
50kW	6 hours / 422	5 hours / 351
75kW	6 hours / 633	3.65 hours / 385
100kW	6 hours / 843	2.99 hours / 420
125kW	6 hours / 1,054	2.60 hours / 456
150kW	6 hours / 1,265	2.34 hours / 493

[9] Assumes 5 years of credit generation using the current credit calculation formula and no actual electricity dispensed.

(TESLA2_FF69-3)

Agency Response: In response to stakeholder feedback, staff proposed to adjust the equation used to calculate the FCI charging capacity for each FSE. The equation now includes a capacity scaling factor based on available cost data for DCFC's of varying power ratings to reflect the non-linear capital cost increase between chargers of increasing power ratings.

I-15. *Credit Calculation for DCFCs*

I-15.1. *Credit Calculation for DCFCs*

Comment: b) CalETC believes the 15-day modifications would allow DC fast chargers to be built and be used (or used a little), and yet still receive the same capacity credits as stations with heavy use. This is because the kWh credits are subtracted from the capacity credits, so chargers receive the same amount of DCFC credit no matter their use. CalETC believes that capacity credits should address up-front cost issues with DCFC and that throughput (kWh) credits should address on-going costs (e.g., demand charges and maintenance). CalETC believes it is important to avoid this type of incentive that encourages less use of the station, and requests that the 15-day modifications allow for capacity and throughput (kWh) credits to be additive (e.g., not part of the capacity credit formula). CalETC also notes that some smaller DCFC stations (e.g., 25 kW curbside) charging should only be receiving throughput (kWh) credits, as they do today.[5]

[5] And this is another reason for making sure there are stand-alone throughput credits that are not part of the DCFC capacity credit formula. Note: these smaller stations along with private stations do not earn capacity credits under the 15-day modifications, but do earn the kWh type of LCFS credit.

c) CalETC believes the 15-day modifications may result in credit value exceeding the cap-ex costs of developing DC fast chargers, and thus do not encourage enough funding from developers. Specifically, CalETC suggests the potential value of infrastructure credits generated should not exceed the capital costs of the DC fast chargers. (CALETC3_FF60-7b)

Agency Response: Staff agrees that FCI credits are intended to support the up-front capital cost of building DCFC's. In section 95486.2(b)(4)(H), staff limited the estimated cumulative FCI credits generated for a DCFC in a given quarter to the difference between the total capital expenditure and the total (or other) revenue received for the station. Staff intends that crediting for throughput would be the most appropriate for supporting operational costs. Staff also proposed that DCFC's must have a minimum nameplate power rating of 50kW to be considered for FCI crediting. However, staff disagrees with the suggestion that capacity credits and throughput credits should be additive (i.e., throughput should not be subtracted from capacity in calculating capacity credits). The intent of the program is that capacity credits will go away as actual throughput builds, as stations would no longer need the capacity credits to be economically viable. Moreover, staff does not agree that the provision as proposed provides incentive that encourages less use of the station. Stations will always be better off economically with increased throughput because the station will receive retail markup on the electricity dispensed as well as the potential to earn incremental credit for low-CI electricity for electricity dispensed. This additional value is not available for a station with little or no throughput.

I-15.2. Multiple Comments: *Cap on Allowable Capacity for DCFC*

Comment: e) CalETC believes it is important for CARB to have the flexibility to adjust to market conditions in the DC fast charge market. Specifically, CalETC does not support the 1.5 MW cap on sites with DC fast chargers. Even today there are exceptions in urban areas where sites are hard to find or along the busiest intercity freeway corridors. CalETC requests amendments that would allow CARB to approve a package of applications for DC fast charge sites between 1.51 and 3.0 MW (limited to no more than 10 percent of incremental DCFC sites that receive capacity credits). (CALETC3_FF60-7e)

Comment: e. increase the site cap to provide developers with more flexibility to meet consumer demands and encourage better economies of scale; and…

…

V. Increase the site cap to provide developers with more flexibility to meet consumer demands and encourage better economies of scale

We support staff's intent to encourage more sites through this pathway; however, certain use cases such as major highway corridors and urban charging, especially to support electric ridesharing services, may warrant more, higher capacity chargers than currently supported by this pathway. The current proposal limits capacity credit generation to 1,500kW at a single site, which equates to 10 chargers assuming max simultaneous power of 150kW per charger. We recommend CARB increase the site cap to 3,000kW (20 chargers at 150kW per charger) to strike a balance between ensuring more sites are deployed and providing developers with additional flexibility to meet consumer demand and encouraging economies of scale. (TESLA2_FF69-5)

Agency Response: In response to stakeholder requests to increase the maximum site capacity, staff proposed to update the maximum total nameplate power rating for all FSE at a single site claiming FCI credits to 2.5 MW. Additionally, staff proposed that the Executive Officer may approve a site up to 6 MW, provided that appropriate justification for the site is submitted, and the total number of FSE with power ratings greater than 2.5 MW do not exceed 10% of total FSE approved under FCI pathways.

I-15.3. Multiple Comments: ***Cap on Allowable Capacity for DCFC***

Comment: a. remove proposed connector requirement (type and ratio) at a site, as this distorts market conditions and hinders automaker investments;

…

I. Remove proposed connector requirement (type and ratio) at a site, as this distorts market conditions and hinders automaker investments

The DCFC industry is still nascent, and technology is rapidly evolving based on market demands. Unlike level 2 charging, which is predominantly SAE J1772, there is no universal DCFC connector that all EVs can use. The FCI pathway should provide flexibility to developers by not imposing restrictions on technology or connector types at this stage of the industry's development.

When Tesla began developing the Supercharger network in 2012, there were no commercially available connectors that enabled fast charging above 62.5kW, and the vast majority of connectors were limited to 50kW. In order to offer drivers a convenient fast charging service for the larger battery packs in our vehicles, Tesla had to design a new connector. Today, with more Model 3 vehicles on California roads, the demand for Tesla-compatible DCFC infrastructure is expected to increase significantly.

Like Tesla, each automaker, when designing a DCFC-capable EV, selects a connector technology (Tesla, SAE CCS Combo Type 1 or CHAdeMO). However, with the exception of the CHAdeMO adapter that very few Tesla customers purchase, there are currently no adapters that would allow an EV to use a DCFC charger that has a different connector. Therefore, Tesla vehicles are unable to use SAE CCS Combo DCFC chargers and only the few Tesla owners who have an adapter can use CHAdeMO DCFC chargers.

Beyond the connector type, it is important to note the varying rates of charge across vehicles. Not all plug-in vehicles are DCFC-capable. There is only one plug-in hybrid model available today that is capable of DCFC. There are approximately a dozen pure battery EVs available for purchase today, and most, but not all, are capable of DCFC. Tesla vehicles are capable of DCFC up to 120 kW while the other DCFC capable vehicles available today are limited to 50 kW.

As our CEO shared on Tesla's 2018 first quarter earnings call, the Supercharger network is not intended to be a walled garden. Tesla is happy to let other automakers

use our Supercharger stations if they pay a share of the cost proportional to their vehicle usage, their vehicles can accept our charger's charge rate and their vehicles can use our connector (directly or with an adapter).[2] At the same time, Tesla will not compromise the performance of our charging hardware for less capable products, possibly leading to congestion and wait times at stations.

[2] Tesla's Q1 2018 Financial Results and Q&A webcast: https://edge.media-server.com/m6/p/nwvzygvo

The current proposal requires at least one-third of connectors at a site to differ from other connectors at the site, regardless of actual market demand for different types of connectors now or in the future, and will result in under-utilized chargers. The connector requirement directly deters automakers, such as Tesla, from participating in this pathway, placing them at a disadvantage as compared to third party charging companies, because automakers would have to install chargers that their vehicles cannot use. Automakers would have to invest the capital and resources to install, maintain and service chargers that their customers cannot use, either directly or through a third party, incurring significant costs and creating unnecessary operational complexity. Ultimately, the challenges that this proposal presents would impede deployment, hindering the state's progress on the Governor's goals.

If the pathway is designed to encourage all developers, including automakers, to deploy DCFC infrastructure, unnecessary technical limitations would only hinder investment and deployment. The pathway should be technology agnostic so the market determines what type of chargers are deployed. Keeping the pathway technology agnostic will help ensure that the pathway funds chargers that are needed to support the vehicles on the road and minimizes the deployment of chargers that will sit idle. If developers are able to select their own mix of connectors based on consumer demand and site limitations, they will be more invested in the long-term viability of the site. The pathway should not force them to fund connector technology that is not core to their business model as it would ultimately result in higher costs and a worse experience for consumers. Therefore, CARB should remove the requirements on the required type and ratio of connectors at each site. (TESLA2_FF69-1)

> **Agency Response:** In response to stakeholder feedback, staff proposed to increase the limit for any one particular connector type at a site from two-thirds to three-fourths. In addition, staff proposed that these connector type requirements would be applicable only for the applications that are submitted after an applicant's estimated potential FCI credits exceed 0.5 percent of total program deficits in the prior quarter. Modifying the requirements in this way provides a higher level of flexibility to allow the market to drive optimal connector protocol ratios, while maintaining accessibility by incentivizing a diverse suite of connector types.

I-15.4. Multiple Comments: *Capacity Determination for DC Fast Charging Equipment for FCI Crediting*

Comment: d. do not subtract actual electricity dispensed from capacity credit formula to encourage developers to optimize for site utilization;

…

IV. Do not subtract actual electricity dispensed from capacity credit formula to encourage developers to optimize for site utilization

The current capacity credit calculation formula, which subtracts actual electricity dispensed, reduces the incentive for developers to optimize projects for utilization. A developer that does not match renewable electricity with DCFC charging would receive the same quantity of credits through the FCI pathway on a 50kW charger that is never used (0kWh of actual electricity dispensed) as a 50kW charger that dispenses 26MWh of electricity every quarter. This could result in developers purchasing cheap land in a rural area and deploying chargers that remain under-utilized in lieu of deploying chargers in more expensive areas.

Although there may be some sites with low utilization, such as sites along rural highway corridors, the vast majority of sites built through this pathway should be located in areas that are optimized for high utilization. The amount of actual electricity dispensed is directly proportional to reducing greenhouse gas emissions and reducing the carbon intensity of the transportation system, so the pathway should encourage the deployment of infrastructure that is more likely to be used. (TESLA2_FF69-4)

Comment: I. Alter the formula so developers are incentivized to deploy ZEV infrastructure in locations with higher, not lower, site utilization.

The draft FCI credit formula misaligns incentivizes for EV infrastructure providers by encouraging development in lower utilization areas. The subtraction of kWh in the formula will have an unintended effect of encouraging an oversupply of EV infrastructure in areas that have ample space and fewer real estate constraints – but few EV drivers – because infrastructure providers will want to build solely to take advantage of the credits. (EVGO1_FF62-2)

> **Agency Response:** Staff proposed to continue subtracting throughput for DCFC's in the capacity credit calculation equation. This feature is included to ensure that the program is self-sunsetting as throughput increases, an indicator which will suggest that crediting for infrastructure is no longer needed. In addition, it is likely that several applicants will utilize the book-and-claim accounting methodology provided in section 95488.8(i), which incentivizes selling fuel and generating associated LCFS credits rather than maximizing infrastructure credits that assume the California Average Grid Electricity CI.

I-16. *Public Availability Requirements*

I-16.1. Multiple Comments: *Open Access for DCFC*

Comment: ChargePoint strongly recommends that the FCI language regarding payment methods reference the final SB 454 guidelines that will be adopted later this year. If the LCFS program preempts or creates a different set of requirements, it could cause confusion, lack of participation in the program, or worse, violations because there

are potentially two different sets of language/requirements around payment methods for public stations. Cross-referencing the current rulemaking will make it more streamlined and easier for EVSE manufacturers and site hosts to meet the requirements. (CHARGEPOINT3_FF39-5)

Comment: d) CalETC does not support the provisions in the 15-day modifications on DC fast charger access and requests these provisions be deleted. Instead, the CARB Board in October 2018 is expected to vote on new regulations (per SB 454) to regulate charging station access for both AC and DC charging stations, so this issue will be addressed very soon. CalETC believes it is appropriate to not have conflicting CARB regulations in this area and the CARB regulations per SB 454 have been going through extensive process with industry and other stakeholders (e.g., invite_only meetings and public workshops). The 15-day modifications on credit card access and related provisions have not gone through a similar process and, and, as a result, are not appropriate given the circumstances. (CALETC3_FF60-7d)

Comment: II. Remove proposed payment method requirements and verification of charging unit performance, as both issues are being addressed through separate rulemakings.

In its proposed plan, CARB suggests that chargers must accept all major methods of payment via credit card or debit card to be eligible for the FCI credit. However, given that a separate rulemaking on payment methods is already ongoing within CARB as it relates to SB 454 and interoperability, we would ask that CARB hold on this requirement for LCFS until a final order has been issued in the interoperability rulemaking process. (EVGO1_FF62-3)

> **Agency Response:** In response to stakeholder comments, the initially proposed requirements for payment methods were simplified given that there is a separate rulemaking process occurring in response to Senate Bill 454 (Corbett, 2013), which addresses the details of access and payment methods for electric vehicle charging stations. Staff modified section 95486.2(b)(4)(C) to only require that FSEs which charge a fee of service must be capable of supporting a public point-of-sale method, accepting all major credit or debit cards.

I-16.2. *Flexibility in Locations for DCFC*

Comment: f) CalETC requests that CARB staff have more flexibility in allowing good locations for DC fast chargers. This is especially important in urban areas where perfect locations that will allow 24-7 access are very hard to find. Specifically, CalETC requests the final LCFS rule allow for up to 10 percent of the sites either 1) the requirement or station access be 16 hours for 363 days per year (or similar) or 2) develop an exception process, e.g., the Executive Officer could be given authority to approve credit generation at sites that do not meet the criteria above based on access considerations. (CALETC3_FF60-7f)

Agency Response: Staff removed the requirement that FSE be open to the public for charging 24 hours per day, 7 days per week, in order to accommodate site-specific limitations on accessibility. Staff instead required disclosure of expected daily permitted hours of operation for the site in section 95486.2(b)(2)(I), and documentation if the daily permitted hours are less than 24 hours. For stations with less than 24 hours access, the percentage of time that the station is available will also be factored into the credit generation equation provided in section 95486.2(b)(5).

I-16.3. ***Point-of-Sale Payment Method Requirements***

Comment: b. remove point-of-sale payment method requirements, as this issue is being addressed by the SB 454 rulemaking;

…

II. Remove point-of-sale payment method requirements, as this issue is being addressed by the SB 454 rulemaking

The proposed language includes a requirement for each charger to be "capable of supporting a public point-of-sale method that accepts credit or debit card without incurring any additional fees, inconvenience or delays versus other payment or access control methods." However, CARB's rulemaking on the Electric Vehicle Charging Stations Open Access Act (Senate Bill 454) would also determine the requirements of point-of-sale payment methods and interoperability for public charging stations. Since this issue is already being addressed by a separate CARB rulemaking, CARB should remove requirements from the FCI pathway especially because those requirements could be retroactively applied.

In general, any point-of-sale payment method requirement should provide the flexibility for companies to meet the evolving needs of consumers, which is moving away from physical card readers on each charger toward mobile payments on the phone or within the vehicle. Mobile payments are becoming increasingly common as more people adopt smartphone and mobile payment technology. The Pew Research Center estimates that 77% of people in the US have a smart phone in 2018, which has more than doubled since 2011, and adoption has been increasing including in lower-income households.[3] Cell phone ownership is estimated at 92% and smartphone ownership at 67% in households earning less than $30,000 per year.[4]

[3] http://www.pewinternet.org/fact-sheet/mobile/

[4] http://www.pewinternet.org/fact-sheet/mobile/

As a result, mobile payments that offer a more seamless experience for customers through an app or within the vehicle will become increasingly popular and accessible. Today, Supercharging sessions, to the extent a customer is charged a fee, are seamlessly completed through the vehicle and requires no additional physical card reader on each charger. Traditional credit card companies such as Visa and MasterCard are also investing in the development of in-vehicle payment options in response to consumer demand for secure, in-vehicle payments.[5] These mobile

payment methods should be recognized as alternatives to physical credit card readers – not simply additional options – especially as credit card ownership continue to decline.[6]

[5] https://www.pymnts.com/the-digital-drive/ and https://www.pymnts.com/news/payment-methods/2017/mastercard-general-motors-partner-on-digital-payments-connected-car/

[6] https://news.gallup.com/poll/168668/americans-rely-less-credit-cards-previous-years.aspx

(TESLA2_FF69-2)

Agency Response: Please see Response I-16.1 in this chapter. Mobile payment options, including those from the vehicle itself, are implicitly included under the language in section 95486.2(b)(4)(C).

I-17. *General Comments*

I-17.1. Comment: CalETC also proposes important amendments to the DC fast charging capacity credit, the exemption for EDUs and two other sections. (CALETC3_FF60-4)

Agency Response: Please see Responses I-10.1, I-11.2, I-14.1, I-15.1, I-15.2, I-16.1, I-16.2, and I-17.2 in this chapter.

I-17.2. Comment: 2. CalETC suggests several amendments the 15-day modification allowing capacity credits for direct current fast charge stations (DCFC). We suggest modifications based on key principles: discouraging overbuilding of charging stations or siting at poor locations; encouraging more funding from station developers; and providing CARB with more flexibility to adjust to market conditions

…

2. CalETC suggests several amendments the 15-day modification allowing capacity credits for direct current fast charge stations (DCFC). We suggest modifications based on key principles: discouraging overbuilding of charging stations or siting at poor locations; encouraging more funding from station developers; and providing CARB with more flexibility to adjust to market conditions

CalETC directionally supports the 15-day modifications on capacity credits for public-access DC fast chargers[4].

[4] A DC fast charger for purposes of LCFS is defined as a parking space or stall that is served by DC fast charge equipment (over 50kW) that has one or more DC connectors to the EV. See section 95486.2 and related definitions.

We recommend amendments to the 15-day modifications in support of these key principles:

a) Encourage smaller DC fast chargers (e.g., 50 kW) to the same degree as larger ones (e.g., 150 kW)

b) Encourage use of public-access DC fast chargers

c) Ensure the potential value of infrastructure credits generated do not exceed the capital costs of the DC fast chargers

d) Allow charging access rules for DC fast chargers to be led by CARB's upcoming regulations in 2018 to implement SB 454 on charging station access (not by LCFS amendments)

e) Provide CARB with limited flexibility to adjust to market needs and allow, if needed, larger DC fast charge stations up to 3 MW

f) Provide CARB with limited flexibility to provide capacity credits for public–access DC fast chargers at good locations (e.g., urban areas) that only allow access for as little as 16 hours a day

g) Encourage the building of DC fast chargers in the early years of the capacity credit (e.g., 2019-2022)

h) Require county weights and measures certification in a later rulemaking. (CALETC3_FF60-7)

Agency Response: Please see Responses I-10.1, I-11.2, I-14.1, I-15.1, I-15.2, I-16.1, and I-16.2 in this chapter.

I-17.3. Comment: 4) HRI Crediting equation - The standard LCFS credit equation and the proposed HRI credit equations do not provide same carbon dioxide reduction values for equal amounts of hydrogen. The standard LCFS equation is section 95486.1(a)(1) uses the energy density of California gasoline or diesel displaced whereas the HRI equation in section 95486.2(a)5 uses the energy density of hydrogen. The amount of LCFS credits earned for 1 kg dispensed hydrogen supplied through identical hydrogen supply pathways are not equal under the current equation methodologies. (AP1_FF16-6)

Agency Response: Staff is unclear as to the issue pointed out by the commenter and believes the commenter may be misunderstanding the credit equations. Both the standard and HRI credit equations multiply the difference of the CI standard and the fuel being reported by the energy density of the fuel being reported. However, it should be pointed out that the standard LCFS credit equation calculates credit generation for dispensed fuel quantities, whereas the HRI equation has been designed to calculate credits using a slightly different methodology based on the difference between the fueling capacity of the station and the dispensed fuel quantity.

I-17.4. Comment: The HRI provision contains a significant number of detailed requirements, for which we offer no position, understanding that the FCEV manufacturers, station operators, and/or hydrogen providers are best poised to provide feedback on these requirements. Thus, we would support additional changes from these stakeholders to streamline the requirements, make the program more effective, and ultimately accelerate hydrogen fueling deployment. (AAMGA1_FF18-5)

Agency Response: Staff acknowledges this comment. Please see Responses I-1, I-2.1, I-2.2, I-2.10, I-4.1, I-5, I-6.1, I-6.2, I-7.1, I-8.1, I-8.2, I-9.1, I-9.2, I-11.1, I-12.1, I-17.3, and T-2 in this chapter that respond to the following

comments submitted by FCEV manufacturers, station operators, and hydrogen providers during the first 15-day comment period: PROTERRA2_FF3-2, 3, 4; AP1_FF16-1, 2, 3, 4, 5, 6, 7; H2IND2_FF17-1, 2, 3, 4, 5, 6, 8, 9, 10, 11, 12; SHELL2_FF57-2, 3, 4, 5, 6, 7, 8, 9; FEF1_FF71-1, 2, 3, 4, 5, 6.

I-17.5. Multiple Comments: ***Ensuring Environmental Integrity of the Program***

Comment: NRDC recognizes ARB staff received direction from the Board during the April 27th Hearing to provide additional credits based on installed infrastructure capacity for hydrogen fuel cell stations, and – out of an interest in promoting Zero Emission Vehicles - has asked staff to also extend these credits to electric-vehicle fast charging stations.[1] While in principle we do not support these types of "incentive, bonus credits" being added to the performance-based LCFS system, we also recognize that ARB has, as a policy matter, sometimes added these types of bonuses into programs. We flag our concerns more generally with the use of incentive multipliers, the trade-offs they generally create, and ask that ARB strengthen the proposed constraints and rules governing the Hydrogen Refueling Infrastructure (HCI) and DC Fast Charging Infrastructure (FCI) credits.

[1] ARB Board Resolution 18-17, April 27th, 2018 Hearing; Governor Jerry Brown's Executive Order B-48-18.

(NRDC3_FF49-1)

Comment: In summary, while we support ARB's overall efforts to adopt changes to the LCFS to extend the program to 2030, we have concerns about ensuring these new provisions – which begins to move the program away from the performance-based approach through the introduction of "incentive bonus" credits – are designed in a manner that ensures the environmental integrity of the program and that the unintended tradeoffs and risks are mitigated to the extent possible. (NRDC3_FF49-5)

Agency Response: Please see Responses I-7.4, I-11.3, and I-13 in this chapter.

I-17.6. Comment: Based on our extensive experience deploying Superchargers in California and around the world, we believe a robust FCI pathway would feature the following characteristics:

1. Supports the development of the nascent DCFC industry by removing barriers to participation (e.g. restrictions on connector types and point-of-sale payment methods) so developers can adapt to evolving customer needs
2. Protects against overbuilding of sites and charger capacity by setting appropriate crediting levels to ensure developers contribute to the total cost of the infrastructure investment (equipment and installation)
3. Encourages faster deployment of chargers to accelerate EV adoption (TESLA2_FF69-13)

Agency Response: Please see Responses I-10, I-14.1, I-15.2, I-15.3, I-15.4, and I-16.3 in this chapter.

I-17.7. Comment: LCFS Staff, at the direction of the Board following the April Board Meeting, have developed a set of proposals for generating LCFS credits based on the capacity of ZEV fueling infrastructure, rather than the actual quantity of fuel dispensed, as is the practice at present. At the time these pathways were proposed, there was no evidence indicating that such an abrupt departure from the established, and quite successful, structure of the existing program was warranted. Despite several conversations with stakeholders over the last several months, we have still not seen such evidence and remain unconvinced that the proposed infrastructure pathway serves an important role in the LCFS. Nevertheless, we recognize the desire to support the expansion of ZEV fueling infrastructure in California and are committed to working with Staff and stakeholders to ensure that the proposed infrastructure capacity pathways achieve their goals in an efficient and equitable fashion. (NEXTGEN3_FF65-8)

Agency Response: Please see Responses I-3.4 and I-6.4 in this chapter.

I-17.8. Comment: CARB's Proposal to Provide "Capacity" Credits for Electric and Fuel Cell Vehicle Infrastructure is Inappropriate and Should Be Eliminated

As part of the 15-day notice, CARB proposes to add a new section, 95486.2 to Title 17, California Code of Regulations. The sole purpose of this section is to provide LCFS credits to hydrogen stations and direct current (DC) fast charging stations for the difference in the installed capacity to deliver hydrogen and electricity in addition to the LCFS credits provided for the "fuel" that is actually delivered to and used by vehicles. In more simple terms, what CARB is proposing is to provide LCFS credits to the owners of hydrogen and DC fast charging stations for taking actions that, in and of themselves, do not result in any actual reduction in greenhouse gas (GHG) emissions or in the carbon intensity (CI) of transportation fuels sold in California. Further, CARB staff is proposing to award these LCFS credits that do not result in any reduction in GHG emissions or CI at levels of up to or perhaps slightly beyond 5%[1] of the GHG emissions associated with the use of deficit generating fuels including conventional gasoline and diesel fuel. As is stated on pages 6 and 7 of Appendix F to the 15-day notice, the purpose of these "capacity" credits for hydrogen and DC fast charging stations is not to reduce actual GHG emissions or lowering the CI level of California transportation fuels, but rather "to support the expansions of such infrastructure as directed by Governor's Executive Order B-48-18." It is inappropriate for CARB to allow what are essentially LCFS credits based on the imagined but unverified use of electricity and hydrogen as transportation fuels that will result in no verifiable environmental benefits and which will effectively decrease the actual GHG reductions associated with the LCFS program by up to 5% depending on the year in question and the degree to which applicants request capacity credits.

[1] More specifically, up to or slightly more than 2.5% would be allowed for both hydrogen and DC fast charging stations for a total of up to or slightly more than 5% if both options are fully subscribed.

Further, CARB has not provided any quantification regarding the magnitude of the potential GHG reductions that could be lost through the capacity credits. The question of the potential magnitude of these lost reductions can be easily addressed using CARB's Illustrative Compliance Scenario.[2] Assuming for purposes of illustration that

capacity credits equal to 5% of deficits are distributed in calendar year 2020 and using the other assumptions of CARB's "LD/High ZEV/20%", the potential lost benefits for calendar year 2020 alone to amount to approximately 820,000 metric tons of GHG emissions[3] which at an LCFS credit price of $100 per metric ton translates into a transfer of roughly $82,000,000 to owners of hydrogen and DC fast charging stations – again just during calendar year 2020. The potential cumulative value of the transfer of money to owners of hydrogen and DC fast charging stations given the parameters of CARB's proposed "capacity" credit provisions is clearly much larger than $82 million.

[2] Available at https://www.arb.ca.gov/fuels/lcfs/rulemakingdocs.htm

[3] Gasoline deficits for 2020 under this scenario 13.6 million metric tons and diesel deficits are 2.79 million metric tons.

It should also be noted that the generation of LCFS credits from actions that do not result in direct reductions in GHG emissions through the proposed "capacity" provisions, will decrease the value of LCFS credits generated by other means that do in fact result in actual reductions in GHG emissions. In order to see that this is the case, one only has to recognize that the "capacity" credit provisions will artificially increase the supply of LCFS credits for which there is a finite demand which in turn will decrease the value of all LCFS credits. (GROWTHENERGY2_FF56-64)

Agency Response: Please see Response I-3, Departure from Fuel Neutral Approach and would not Represent Actual GHG Emission Reductions, in this chapter for a rationale for the infrastructure crediting provisions. In addition, CARB has provided a quantification of the potential GHG reductions due to the proposed amendments, which include the capacity credits provision, in the Illustrative Compliance Scenario Calculator posted on August 15, 2018. The updated Illustrative Compliance Scenario Calculator explicitly quantifies the potential GHG reduction in a variety of scenarios as well as the alternatives discussed in the economic analysis included in the ISOR's Appendix E.

Staff acknowledges that the addition of the capacity credits—as well as the inclusion of other provisions that increase the flexibility provided to existing credit producers, or the types of fuels that eligible to participate in the program—might have the potential of increasing the future supply of credits, which may potentially lead to a decrease the price of the LCFS credits. That said, higher investment in ZEV refueling infrastructure may lead to a more rapid adoption of ZEVs in California, leading to more rapid reductions in the carbon intensity of fuels in California and greater GHG emission reductions.

J. Pathway Application and Carbon Intensity Determination

J-1. *Support for Modifications to the Pathway Application and Carbon Intensity Determination Provisions*

J-1.1. Multiple Comments: *Support for the Updates to the CA-GREET3.0 Model and Simplified CI Calculators*

Comment: RFA applauds CARB staff for its continued efforts to update the CA-GREET modeling platform and ensure the tool accurately represents current practices and trends in low-carbon fuel production. RFA supports many of the improvements to the CA-GREET 3.0 model and associated CI calculators, as proposed in the 15-day package. (RFA3_FF30-5)

Comment: REG appreciates all of the work which have gone into updating the Simplified GREET model over the past several months. (REG3_FF44-21a)

> **Agency Response:** Staff appreciates support for updates and improvements to the CA-GREET3.0 model and Simplified CI Calculators.

J-1.2. *Support for the Updates to the Farm-to-Plant Corn Transport Distance*

Comment: We support modifying the farm-to-plant corn transport distance to 40 miles, although the literature supports an even lower value; (RFA3_FF30-6)

> **Agency Response:** Staff appreciates support related to updating the farm-to-plant corn transport distance to 40 miles. For facilities which can demonstrate transport distance lower than the conditional default value, a site-specific option is available.

J-1.3. *Support for the Updates to Heavy and Medium Heavy-Duty Truck Capacities*

Comment: RFA agrees with CARB's proposal to adjust heavy and medium heavy-duty truck capacities for farm-to-plant feedstock delivery; (RFA3_FF30-7)

> **Agency Response:** Staff appreciates support for updates to heavy and medium heavy-duty truck capacities.

J-1.4. *Support for the Updates to the Fuel Economy of Heavy and Medium Heavy-Duty Truck Capacities*

Comment: We support the proposed changes to fuel economy default values for heavy and medium heavy-duty trucks; and… (RFA3_FF30-8)

> **Agency Response:** Staff appreciates support for updates to fuel economy of heavy and medium heavy-duty trucks.

J-1.5. *Support for the Upgrade to eGRID Data in the CA-GREET3.0 Model*

Comment: We agree with CARB's proposal to update the eGRID data in CA-GREET 3.0 to reflect the more current EPA values. (RFA3_FF30-9)

> **Agency Response:** Staff appreciates the support for the upgrade to eGRID data in the CA-GREET3.0 model.

J-1.6. *Support for Modifications to the Dairy and Swine Pathways*

Comment: EcoEngineers supports increased transparency and guidance for dairy and swine digesters to participate in the LCFS program and thanks staff for adding section §95488.9(f) and reducing the temporary pathway CI value for dairy manure to -150. (ECOENGINEERS2_FF21-2)

> **Agency Response:** Staff appreciates support related to dairy and swine pathways in the LCFS program.

J-1.7. Multiple Comments: *Support for the Update to the Dairy Biomethane Temporary Carbon Intensity Value*

Comment: a. We support the change in section 95488.9(b) to set a temporary pathway CI value of dairy biomethane to -150 gCO2e/MJ. This level accounts for the beneficial impact of avoided dairy manure methane emissions, while also being conservative in its estimate of the magnitude. This approach is appropriate for new facilities. (MEW1_FF40-7)

Comment: a. We support the change in section 95488.9(b) to improve the temporary CI value of dairy biomethane to -150 gC02e/MJ. Recognizing the outstanding CI reduction in dairy biomethane will help support this new industry in the state. (CRF2_FF42-4)

Comment: RNG Coalition supports the proposed update to the temporary fuel pathway table value for biomethane derived from dairy/swine manure from zero to -150 gCO_2e/MJ. As we noted in our prior comments, we believed the previous value was unreasonably high. We thank you for the more reasonable updated value. (RNGC3_FF46-6)

Comment: We would like to express our support and appreciation for the change of the temporary CI to -150. (CALBIO1_FF67-6)

Comment: Bluesource supports increased transparency and guidance for dairy and swine digesters to participate in the LCFS program and thanks staff for adding section §95488.9(f) and reducing the temporary pathway CI value for dairy manure to -150. (BLUESOURCE1_FF70-1)

> **Agency Response:** Staff appreciates support for the update to the dairy biomethane temporary CI value. In response to BLUESOURCE1_FF70-1, staff

appreciates support for transparency and guidance related to dairy and swine digester projects.

J-1.8. *Support for the Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure*

Comment: PG&E supports renewable natural gas as a transportation fuel for customers whose transportation needs are not met by zero emission technologies today. Additionally, we support the state's effort to limit emissions of short-lived climate pollutants. As such, we are supportive of ARB's inclusion of a Tier 1 Simplified CI calculator for biomethane from Anaerobic Digestion of Dairy and Swine Manure and other pathways for renewable natural gas. This will encourage renewable natural gas suppliers in the state to opt-in to the LCFS program, generate credits, and increase market liquidity. (PGE2_FF64-7)

> **Agency Response:** Staff appreciates support for the Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure and other pathways for renewable natural gas.

J-2. *CA-GREET3.0 Model*

J-2.1. Multiple Comments: *Tallow Rendering Energy*

Comment: There are two aspects of the CA GREET 3.0 that have issues, the tallow rendering energy…

The tallow rendering energy in GREET 2017 was significantly reduced as the pervious versions had misinterpreted the data in the peer reviewed paper that was used as the data source. The issue is discussed in the GREET memo which can be found here (https://greet.es.anl.gov/files/beef_tallow_update_2017). This is a simple correction of an error in GREET 2016 and it should be incorporated into CA GREET 3.0 and the BD/RD Simplified Calculator. It has a significant impact on the tallow pathways. (NBBCABA3_FF4-13)

Comment: As part of the 2018 LCFS program amendments, ARB has proposed modifications to the 2016 CA-GREET model to create CA-GREET 3.0. Diamond Green Diesel is concerned the recent changes to the California GREET 3.0 model do not fully account for errors in the 2016 CA-GREET. While ARB corrected the energy used for crushing soybeans, they neglected to correct for the tallow rendering energy value in CA-GREET 3.0.

The tallow rendering change made to GREET 2017 is based on a memorandum from Argonne National Laboratory issued on October 9, 2017 (Chen, R. Updates on the Energy Consumption of the Beef Tallow Rendering Process and the Ratio of Synthetic Fertilizer Nitrogen Supplementing Removed Crop Residue Nitrogen in GREET). In this memorandum, Argonne acknowledges it misinterpreted data in the peer reviewed literature on the energy used for rendering. The energy use for rendering in GREET 2017 was then corrected for the mistake. CARB should apply this correction to

California GREET 3.0. The changes to California GREET 3.0 are straightforward and only involve correcting input data. Furthermore the changes do not impact any other pathway.

To fail to make this change results in an erroneous and substantially higher carbon intensity for renewable diesel made from tallow. This would be extremely unfortunate given the science is clear that tallow should have a lower Carbon Intensity (CI) number. Additionally it would be inconsistent and counterproductive for CARB to grant changes from GREET 2017 that affect one feedstock (soybean oil), but not permit similar changes from GREET 2017 for another feedstock (tallow). Therefore Diamond Green Diesel strongly urges CARB to implement the lower tallow rendering change made to GREET 2017. (DGD2_FF12-1)

Comment: Diamond Green uses only low-carbon sustainable feedstocks including tallow, used cooking oil, and distiller's corn oil to produce a low carbon renewable diesel. As part of the 2018 LCFS program amendments, ARB has proposed modifications to the 2016 CA-GREET model to create CA-GREET 3.0. Diamond Green Diesel is concerned the recent changes to the California GREET 3.0 model do not fully account for errors in the 2016 CA-GREET. While ARB corrected the energy used for crushing soybeans, they neglected to correct for the tallow rendering energy value in CA-GREET 3.0.

The tallow rendering change made to GREET 2017 is based on a memorandum from Argonne National Laboratory issued on October 9, 2017 (Chen, R. Updates on the Energy Consumption of the Beef Tallow Rendering Process and the Ratio of Synthetic Fertilizer Nitrogen Supplementing Removed Crop Residue Nitrogen in GREET). In this memorandum, Argonne acknowledges it misinterpreted data in the peer reviewed literature on the energy used for rendering. The energy use for rendering in GREET 2017 was then corrected for the mistake. CARB should apply this correction to California GREET 3.0. The changes to California GREET 3.0 are straightforward and only involve correcting input data. Furthermore the changes do not impact any other pathway.

To fail to make this change results in an erroneous and substantially higher carbon intensity for renewable diesel made from tallow. This would be extremely unfortunate given the science is clear that tallow should have a lower Carbon Intensity (CI) number. Additionally it would be inconsistent and counterproductive for CARB to grant changes from GREET 2017 that affect one feedstock (soybean oil), but not permit similar changes from GREET 2017 for another feedstock (tallow). Therefore Diamond Green Diesel strongly urges CARB to implement the lower tallow rendering change made to GREET 2017. (DGD3_FF25-1)

Comment: There are two aspects of The NBB's comments which REG would like to strongly emphasize: the need to update the emission factor for tallow rendering... (REG3_FF44-22a)

Agency Response: Applicant data for tallow rendering, submitted as part of pathway certification in the LCFS program, do not support lowering tallow rendering energy to a value used in the Argonne GREET model. Additionally, the BD/RD Simplified CI Calculator includes a provision to allow applicants processing tallow at their facilities to request a site-specific rendering energy for their feedstock.

J-2.2. Multiple Comments: *Truck Transport in CA-GREET3.0*

Comment: There are two aspects of the CA GREET 3.0 that have issues, … the changes that CARB as made to the transportation energy use and resulting emission factors. (NBBCABA3_FF4-14)

Comment: There have been changes made to the transportation energy use for feedstocks and fuels after it was pointed out that in the previous version of CA GREET 3.0 a medium duty truck in the model was more efficient than a heavy-duty truck, which is not true. Unfortunately, CARB has made a number of other adjustments that have introduced new issues. (NBBCABA3_FF4-14a)

Comment: RFA disagrees that back-haul miles should be added for rail and truck transport, as we believe those miles (and related emissions) are already captured inGREET1_2016 (Argonne) and thus CA-GREET 3.0. Adding another factor for back-haul miles in CA-GREET 3.0 would result in double-counting of back-haul miles and emissions for rail and truck transportation. (RFA3_FF30-10)

Agency Response: Comments state that a medium-duty truck should be less energy efficient than a heavy-duty truck; however, in references CARB collected (for example, the table below is a summary of one NHTSA report)[60], the fuel economy (mile/diesel gallon, or MPG) of the medium-duty truck (Class 6) is generally higher than the heavy-duty truck (Class 8).

	MPG at 50 Percent Payload	
	HDT (Class 8)	MDT (Class 6), ISB Engine
CARB	4.63	7.7
55 MPH	8.12	9.7
65 MPH	6.75	8.0
WHVC/WTVC	6.2	9.2

For an additional response to a comment on truck transport, see response to GROWTHENERGY1_B4-23b in the Response to Comments on the Draft

[60] Commercial medium- and heavy-duty truck fuel efficiency technology study – Report #1. (Report No. DOT HS 812 146). Washington, DC: National Highway Traffic Safety Administration. Reinhart, T. E. (2015, June [Revised October 2015]).

Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

Please see Response J-2.3 in this chapter regarding updates to rail transport.

Please see Responses J-2.4 and J-2.5 in this chapter for “other adjustments” stated in the comments.

J-2.3. Multiple Comments: *Rail Transport in CA-GREET3.0*

Comment: For the Rail energy use, CARB has added the same amount of energy as backhaul energy for rail movement. This is not necessary as the energy use for rail is calculated by taking the total fuel used for class 1 railroads and dividing that by the ton-miles of freight moved by those railways. This calculation automatically includes the energy used for back hauls and thus it is not necessary to double the value. However, even if it was not already included, it would not be the same value as the energy for a loaded car. There is really no justification given for adding the backhaul energy in Attachment C.

The ORNL Transportation Energy Data Book edition 36 reports (Table 9.8) that the total freight moved in 2015 was 1.744 million ton-miles and the energy used by the railroads was 516.4 trillion BTU for a total energy use of 294 BTU/ton-mile which would include the movement of empty cars. CA GREET 3.0 has 274 BTU/ton-mile for loaded and the same energy for unloaded movements. This is not correct and the back haul energy for rail should be removed from the model. The methodology is reported in section 6.2 of Appendix A. (NBBCABA3_FF4-14b)

Comment: Growth Energy has reviewed CARB’s calculation of direct emissions for corn ethanol, which continue to be overstated. First, for its rail energy use, CARB has added the same amount of energy as backhaul energy for rail movement. This overstates rail emissions because the energy use for rail already includes backhaul energy. (See Exhibit “A” at 2.) Rail emissions are also overstated because they erroneously include the same energy use for both loaded and empty cars. (*Id.*) (GROWTHENERGY2_FF56-14)

Comment: For rail energy use, ARB has added the same amount of energy as backhaul energy for rail movement. This is not necessary as the energy use for rail is calculated by taking the total fuel used for class 1 railroads and dividing that by the ton-miles of freight moved by those railways. This calculation automatically includes the energy used for back hauls; thus, it is not necessary to double the value. However, even if the backhaul energy was not already included, it would not be the same value as the energy for a loaded car. There is really no justification given for adding the backhaul energy in Attachment C.

The ORNL Transportation Energy Data Book Edition 36 reports (Table 9.8) that the total freight moved in 2015 was 1.744 million ton-miles and the energy used by the railroads was 516.4 trillion BTU for a total energy use of 294 BTU/ton-mile which would include the movement of empty cars.[1] CA GREET 3.0 has 274 BTU/ton-mile for

loaded and the same energy for unloaded movements. This is not correct and the back haul energy for rail should be removed from the model. The methodology is reported in section 6.2 of Appendix A.

[1] https://info.ornl.gov/sites/publications/Files/Pub104063.pdf

(GROWTHENERGY2_FF56-60)

> **Agency Response:** Staff inadvertently double-counted the rail transport emission factor. This has been corrected in the final CA-GREET3.0 model and all Simplified CI Calculators.

J-2.4. Multiple Comments: *Road Transport in CA-GREET3.0*

Comment: The road energy use in GREET is calculated by taking the vehicle fuel consumption and load and from that calculating the BTU/ton-mile. There is no equivalent data set as exists for the railways in which the total fuel used and the total freight moved is available, so the approach in GREET is reasonable. In this version of CA GREET, CARB has changed the load size and the fuel economy. As a result of these changes, the energy use for a HD truck for soybeans has been reduced from 3231 BTU/ton-mile to 1574 BTU/ton-mile and the energy use for the back haul is 79.3% of the loaded energy use. The US DOE report that a loaded class 8 truck typically weighs three times the unloaded vehicle weight (https://www.energy.gov/eere/vehicles/fact-621-may-3-2010-gross-vehicle-weight-vs-empty-vehicle-weight). The back haul energy use should be closer to the ratio of the weight of unloaded vehicle to the fully loaded vehicle, that is 33%. There is no explanation for the new fuel economy values used by CARB.

While the energy use for the heavy-duty trucks decreased, the values for the medium duty trucks increased from 3088 BTU/ton-mile to 6231 BTU/ton-mile. The primary reason for this is that the load size was cut almost in half along with a reduction in the miles per gallon. No source for the data is provided and the back haul energy is the same 79.3% of the loaded energy, which is again too high a value. The DOE reports that the medium-sized trucks (truck classes 3-6) have payload capacity shares between 50% and 100% of the unloaded weight, which suggests that the back haul energy use should be 50 to 66% of the loaded energy use. (NBBCABA3_FF4-14c)

Comment: Road emissions for corn ethanol are likewise overstated. The new version of CA GREET has changed the load size and fuel economy of vehicles in a manner unsupported by the evidence. For example, the energy use contemplated for certain heavy duty unloaded vehicles is 79.3% of the loaded vehicles, while U.S. DOE studies show the same loaded vehicles are three times the weight of unloaded vehicles (meaning that the energy use of unloaded vehicles should be closer to approximate 33% of a loaded vehicle). (See Exhibit "A" at 2.) U.S. DOE data likewise shows that backhaul (unloaded) energy use for medium duty vehicles is approximately 50-66% of loaded energy (compared to 79.3%). (*Id.*) (GROWTHENERGY2_FF56-15)

Comment: The road energy use in GREET is calculated by taking the vehicle fuel consumption and load and from that calculating the BTU/ton-mile. There is no

equivalent data set as exists for the railways where the total fuel used and the total freight moved is available, so the approach in GREET is reasonable. In this version of CA GREET 3.0, however, CARB has changed the load size and the fuel economy without explanation. As a result of the changes, the energy use for a HD truck for corn has been reduced from 3231 BTU/ton-mile to 1574 BTU/ton-mile and the energy use for the back haul is 79.3% of the loaded energy use. This is not accurate. The US DOE reported that a loaded class 8 truck typically weighs three times the unloaded vehicle weight.[2] As a result, back haul energy use should be closer to the ratio of the weight of unloaded vehicle to the fully loaded vehicle that is 33%. There is no explanation for, or evidence to support, the new fuel economy values used by CARB.

[2] https://www.energy.gov/eere/vehicles/fact-621-may-3-2010-gross-vehicle-weight-vsempty-vehicle-weight.

While the energy use for the heavy-duty trucks decreased, the values for the medium duty trucks increased from 3088 BTU/ton-mile to 6231 BTU/ton-mile. The primary reason for this is that the load size was cut almost in half along with a reduction in the miles per gallon. No source for the data is provided and the back haul energy is the same 79.3% of the loaded energy, which is again too high a value. Specifically, the DOE reports that the medium-sized trucks (truck classes 3-6) have payload capacity shares between 50% and 100% of the unloaded weight, which suggests that the back haul energy use should be 50% to 66% of the loaded energy use. (GROWTHENERGY2_FF56-61)

> **Agency Response:** Please see the responses to GROWTHENERGY1_B4-23b and GROWTHENERGY1_B4-23c in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations. The updated fuel economy, energy consumption and energy intensity of the HDT and the MHDT were provided by the GREET development team at Argonne National Laboratory. The updated value considers high fuel economy for unloaded trucks.

J-2.5. Multiple Comments: *Barge Transport in CA-GREET3.0*

Comment: CARB has not changed the barge energy use in the latest version of CA GREET 3.0. We previously submitted comments regarding the fact that the barge energy use is higher than rail energy use and that this is not supported by the literature. Our previous comments are repeated here.

The rail and domestic water energy use in CA GREET is compared to the data from the Transportation Energy Data Book in the following table.

	CA GREET	Transportation Energy Use Data Book
	BTU/ton mile	
Rail	274	292
Barge	735	214

In both cases the methodology is to take the total energy consumption for the mode and the total ton-miles of freight moved. This automatically accounts for the "back-haul" and there is no need to add additional energy for this movement as is done in CA GREET. It appears that the barge transport emission factor in CA GREET is too high by a factor of 3.4.

This is confirmed by the recent National Academies publication "Funding and Managing the U.S. Inland Waterways System: What Policy Makers Need to Know (2015)". In appendix G[2] where it is stated that:

[2] Appendix G. https://www.nap.edu/read/21763/chapter/15

> Some studies show barge to be more energy efficient, while others show rail as the more energy-efficient mode. In terms of British thermal units per ton-mile, Davis et al. report that rail (294 Btu/ton-mile in 2012) is 40 percent more energy intensive than barge (210 Btu/ton-mile in 2012), nearly the same percentage difference as reported by Kruse et al. (2013).[1] These average energy intensity values represent the two-way transport average of upstream and downstream transport (upstream transport may require more energy to account for barge movement against downstream current velocities, and downstream transport energy may benefit from the river current). Alternatively, Dager (2013) reports even lower energy intensity for inland barge transport on the basis of independent data and fuel use modeling, corresponding to about 196 Btu/ton-mile, or about 60 percent better energy intensity than average rail. (NBBCABA3_FF4-14d)

Comment: There are two aspects of The NBB's comments which REG would like to strongly emphasize: …barge transportation. (REG3_FF44-22b)

Comment: Both of these factors have been grossly overestimated for far too long. The barge transportation mode is grossly overestimated by nearly a factor of 3.5 times of the actual carbon intensity. This acts to punish one of the safest and lowest emissions modes of transportation for movement of fuel and feedstock on America's vast inland waterway system. (REG3_FF44-23)

Agency Response: Please see Response J-6.22. in Chapter IV.

J-2.6. *Change in Carbon Intensity Values for Liquefied Hydrogen Pathways*

Comment: Although most of the changes to Table 7-1 were relatively small, the CI values for the liquefied hydrogen pathways (HYFL and HYBL) changed by over 20 gCO2e/MJ. The Notice of Availability of Modified Text released on June 20, 2018, indicates that changes to Table 7-1 CI values were a result of updates to the transportation and distribution parameters in CA-GREET3.0. However, a review of Table F.3 in Appendix C to the 15-Day Modifications indicates that liquefaction CI decreased by 25.71 gCO2e/MJ. The basis for this change is unclear, as the liquefaction efficiency does not appear to have changed based on inputs summarized in Tables F.4 and F.6 of Attachment C. WSPA requests clarification for the basis of this change to the liquefied hydrogen pathways in Table 7-1. (WSPA5_FF19-7)

Agency Response: The liquefied hydrogen pathways in the Lookup Table assume that the liquefaction process occurs in-state using California grid electricity. The model released on March 6, 2018 erroneously linked the electricity mix to the U.S. average mix. Fixing this error resulted in a significant reduction in the CIs for the HYFL and HYBL pathways. Additionally, other indirect changes in CA-GREET3.0, such as the energy intensity updates of various transportation modes and the update of eGRID data also contributed to minor changes model-wide. All changes made to the CA-GREET3.0 model are detailed in the supplementary document.

J-2.7. *Change in Carbon Intensity Contribution for CARBOB Refining*

Comment: Table A.5 shows a change to the CI contribution of CARBOB refining under the CA-GREET 3.0 column, from 14.92 to 14.81, but there are no reported changes to the efficiency or the share of other energy inputs for the 15-day Modifications. WSPA requests that ARB clarify this change in CI contribution. (WSPA5_FF19-22)

Agency Response: Staff did not modify any parameters which directly affect the refining process of CARBOB. However, other indirect changes in CA-GREET3.0, such as the energy intensity updates of various transportation modes and updates to eGRID data, have contributed to minor changes model-wide.

J-2.8. *Carbon Intensity of Propane*

Comment: 2. Relative Roles of Natural Gas Processing and Petroleum Refining to Produce Transportation Propane Used in California.

Summary of Specific Concerns

Staff's proposed lookup table for "fuels that substitute for gasoline and diesel" assigns fossil propane a CI value of 83.65 gCO2e/MJ. This is based on an assumption specifying the fractions of California's transportation propane currently produced from petroleum refining versus that produced from natural gas processing. Based on previous Staff comments, it appears CARB assumes natural gas-derived propane constitutes only about 25 percent of this mix. As described below -- based on an analysis by ICF and an internal survey -- WPGA concludes that nearly double the percentage assumed by Staff is produced through the natural gas pathway, instead of the more-carbon-intense petroleum pathway. Clearly, Staff's existing assumption results in an overestimation for the CI of propane derived from petroleum. Updating the assumptions relating to propane feedstock fractions is critical to improving the accuracy of the CI assigned to fossil-based propane in California.

Corroborating Report from ICF

ICF, on behalf of WPGA, has just completed a draft report titled "Report on Propane Supply Sources for California." This report is being submitted confidentially to CARB. We have also summarized its key finding. As shown in the summary quote below, ICF

estimates that the relative percentages for the average way that transportation propane is produced (for California vehicles) is **42 percent natural gas processing / 58 percent petroleum refining.**

> *"This report details ICF's assessment on the production source and type of production of the propane consumed within the state of California. The assessment is based on a combination of ICF's analysis of propane consumption levels, transportation options, and propane supply sources as well as publically available data sources that include the Energy Information Agency (EIA), the Canadian National Energy Board (NEB), and the U.S. International Trade Commission (ITC). This assessment evaluates supply, consumption, import, and export levels in 2016.*
>
> *While data on propane supply and transportation is not definitive, based on the available data on propane production, imports, exports, and transportation,* ***ICF estimates that in 2016, 42 percent (238 million gallons out of 568 million gallons) of the odorized propane consumed in California was sourced from natural gas processing plants****. Propane from natural gas plants is sourced in-state (26 percent), from Western Canada (72 percent) and from the U.S. Rocky Mountain region (2 percent). The remaining 58 percent of the propane consumed in California, or 330 million gallons, is sourced from propane produced by California refineries."*[5]

[5] ICF, "Report on Propane Supply Sources for California," prepared for the Western Propane Gas Association, July 5, 2018.

Internal WPGA Survey

WPGA surveyed members to provide even greater detail regarding the percentage of propane derived from natural gas pathways versus petroleum pathways. A confidential member survey will be submitted to CARB that shows 45% of California's propane is derived from natural gas pathways and not the more carbon-intense petroleum pathway. California actually exports significant propane production volume to Mexico from Southern California petroleum-based refineries. One result of propane exports is that more fuel utilized in-State is derived from natural gas pathways.

Recommended Staff Actions

WPGA respectfully asks that Staff review the confidential ICF report and WPGA member survey, and incorporate this 45 percent / 55 percent split for the average way that California propane is produced. This will downwardly revise the baseline assumption of 83.65 gCO2e/MJ for the CI of fossil propane.

…

We respectfully ask that Staff take the following actions, to make the regulation as accurate as possible with respect to how California's transportation propane is produced and utilized:

…

- Review the ICF draft report and WPGA member survey (both sent confidentially to CARB) and incorporate a 45 percent / 55 percent split for the average way that California propane is produced. (WPGA3_FF58-3)

  Agency Response: Please see Response J-2.12.from Chapter IV.

J-2.9. *Increase in Carbon Intensity for Electricity for EV Charging*

Comment: 4. CalETC opposes the 15-day modification that increases the California grid-average carbon intensity to 95.54 grams per MJ $CO2_e$. We request this 15-day modification be deleted as CARB staff works with stakeholders to correct the errors in this increased CI value.

…

4. CalETC opposes the 15-day modification that increases the California grid-average carbon intensity to 95.54 grams per MJ $CO2_e$. We request this 15-day modification be deleted as CARB staff works with stakeholders to correct the errors in this CI value.

Working with the Electric Power Research Institute, CalETC evaluated the 15-day modified grid-average carbon intensity. We believe there are errors in the calculation of the 95.54 grams. For example, the CARB staff calculations incorrectly assign upstream emissions and the geothermal power plant emission calculations are too high. CalETC will continue to work with staff on this complex topic to develop a more accurate number. (CALETC3_FF60-9)

> **Agency Response:** There were incorrect cell references in the June 2018 version of the model used to calculate CI for Electricity for EV charging. Staff has corrected these pointing errors associated with upstream emissions and geothermal fugitive CO_2 emissions in CA-GREET3.0, based on the California electricity resources mix (CEC 2016) of the Lookup Table pathway for California Average Grid Electricity provided to electric vehicles in California. The updated CI for Electricity for EV charging accurately represents the CI for this pathway.

J-2.10. Multiple Comments: *Renewable Power Use in Hydrogen Pathways*

Comment: <u>Renewable Power Usage in Production, Distribution, and Dispensing:</u> Electrical power is an important input in all aspects of hydrogen production, compression, liquefaction, distribution, and dispensing. Electricity is the primary input when hydrogen is produced by electrolysis from water, but electrical power is also a significant source of energy for compression, liquefaction, pumping, and refrigeration of hydrogen produced by any method. Therefore, it is important that the LCFS regulations recognize renewable electricity as such whenever it is used in a hydrogen pathway.

For example, in proposed Sections 95481, 95486, and 95488, the credits available for improvements in the CI of electricity used for the production of hydrogen by electrolysis should also be available for improvements in the CI of electricity used for compression, liquefaction, distribution or dispensing.[2] Further, the *Time-of-Use* pathway definition

(rather than *Smart Electrolysis* definition) should be restored to include electrical power used in all hydrogen production pathways.[3] Lastly, the Book-and-Claim Accounting should be allowed for use for all aspects of hydrogen production.[4]

[2] **Section 95481.(a)(113)** "Renewable Hydrogen" means hydrogen derived from (1) electrolysis of water or aqueous solutions using renewable electricity; (2) catalytic cracking or steam methane reforming of biomethane; or (3) thermochemical conversion of biomass, including the organic portion of municipal solid waste (MSW). Renewable electricity, for the purpose of renewable hydrogen production by electrolysis ***or for hydrogen compression, liquefaction, distribution or dispensing,*** means electricity derived from biomass, including the organic portion of MSW, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, electricity generated from a small hydroelectric facility of 30 megawatts or less, biogas, ocean wave, ocean thermal, and tidal current.

[3] **Section 95486.1(e)(2):** ***Time-of-Use Pathways*** for Hydrogen Production. An entity can generate credits, in addition to credits generated pursuant to subsection (1), above, for improvements in the CI of electricity used for electrolysis***, or for hydrogen compression, liquefaction, distribution or dispensing,*** to produce hydrogen due to time of use smart electrolysis pursuant to section 95488.5 and the credit calculation in section 95486.1(c)(2)(B), where: Electricity is the total quantity of low-CI electricity supplied to the electrolyzer for hydrogen production***, or used for hydrogen compression liquefaction, distribution or dispensing***.

[4] **Section 95488.8(i)(1):** *Book-and-Claim Accounting for Renewable or Low-CI Electricity Supplied as a Transportation Fuel or Used to Produce Hydrogen.* Reporting entities may use indirect accounting mechanisms for renewable electricity to reduce the CI of electricity supplied as a transportation fuel or for hydrogen production through electrolysis***, and for hydrogen compression, liquefaction, distribution or dispensing***, provided the conditions set forth below are met:

Similar changes would follow in Section 95488.1, Section 95488.5, Section 95488.10(a)(4) and Section 95491. Without these changes, a hydrogen producer has very limited incentive to improve renewable content within a given pathway. (H2IND2_FF17-7)

Comment: Recognizing renewable electricity as such whenever it is used in a hydrogen pathway – including production, compression, liquefaction, distribution, and dispensing – would more accurately reflect choices in electricity supply that impact hydrogen pathway carbon intensity. (SHELL2_FF57-6)

Agency Response: In response to Book-and-Claim Accounting, please see Response J-13 in Chapter IV.

If renewable electricity is used directly (behind the meter), it is allowed to lower the carbon intensity score of renewable hydrogen. This approach has been consistently applied to other pathways. Staff changed the terminology from time-of-use (TOU) to smart charging/smart electrolysis to avoid any confusion with utility offered time-of-use rate. For all practical purposes, smart electrolysis means the same thing as the Time-of-Use pathway definition, hence staff does not believe that it is necessary to revert back to the old terminology.

Please see Response D-6.8, Smart Electrolysis and Indirect Book-and-Claim Accounting for Low-CI or Renewable Electricity for Hydrogen Production, in Chapter VI regarding the availability of smart charging for electricity used as a process fuel.

J-2.11. *Corn Transport Distance*

Comment: GREET1_2016 (Argonne) appears to assume that corn feedstock that is shipped via rail to ethanol plants outside of the Corn Belt is first transported 50 miles by truck to the rail terminal. Empirical data show the corn transport distance from farm-to-rail terminal is likely 20 miles or less. We request that CARB modify this transport distance in CA-GREET 3.0. (RFA3_FF30-11)

> **Agency Response:** The empirical data provided by RFA refers to a study carried out by North Dakota State University (2015)[61]. This report analyzed corn delivery by truck in four states: Montana, South Dakota, North Dakota, and Minnesota. The transport distance mentioned by RFA refers to the first choice delivery point. The first choice delivery point is not always to the rail terminal. In fact, only 50 percent of the first choice delivery point refers to delivery to the rail terminal. For the second choice delivery point, the transportation distance is about 40 miles. Moreover, the report excludes major corn producing states like Iowa and Nebraska. Staff updated the transport distance from stack to rail-yard to 40 miles to reflect the more conservative transport distance from this report.

J-2.12. Multiple Comments: *Distillers' Grain Methane Credit*

Comment: The most current version of the GREET model includes a distillers' grains (DDG) methane avoidance credit, which equals 2.1 g/MJ, and is not incorporated into CA GREET 3.0 under the Proposed Modifications. (GROWTHENERGY2_FF56-33)

Comment: The modifications proposed in the 15-day notice do not include any revisions addressing our prior comments on distillers' grains reducing enteric fermentation. This is a factor that is included in the GREET2016 model, from which the CA GREET3.0 is derived. The GREET2016 model DG enteric fermentation credit for corn ethanol is estimated at 2,260 g CO2e/mmBTU of ethanol (2.1 gCO2e/MJ). As we pointed out in our prior comments dated April 23, 2018, ARB's main reason for not including this factor appears to be that the animals consuming the DGS rations are not currently in the LCFS LCA ethanol system boundary. However, we previously noted that ARB has made exceptions to boundary conditions for other pathways, and we further pointed out that ARB's position on this is also inconsistent with ISO lifecycle assessment standards. To be consistent with the best available scientific information, the LCFS should be updated to include this DG credit at this time. (GROWTHENERGY2_FF56-59)

> **Agency Response:** Please see responses to GROWTHENERGY1_B4-23a and GROWTHENERGY1_B4-54b in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

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[61] Vachal. Kimberly. Northern Plains Grain Farm Truck Fleet and Marketing Patterns. Upper Great Plains Transportation Institute, Department Publication No. 284, North Dakota State University (2015).

J-2.14. ***Errors in Simplified Calculators***

Comment: CA GREET 3.0 uses simplified calculators for corn ethanol and sugarcane ethanol that contain several errors. Unless corrected, the CI for sugarcane ethanol will be understated, and the CI for corn will be overstated. (GROWTHENERGY2_FF56-38)

> **Agency Response:** Please see responses to GROWTHENERGY1_54g and GROWTHENERGY1_54l in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

J-2.15. ***Corn Ethanol CI***

Comment: Although the ISOR estimates that the CI for corn ethanol will drop from approximately 70 g/MJ to 45 g/MJ, it is unclear what evidence the Executive Officer relied upon to determine corn ethanol facilities would install CCS systems at a rate necessary to reduce their CI to 45 g/MJ. As a result, Growth Energy urges CARB to swiftly consider the approval of the proposed pathways for such fuel to help provide evidentiary support for CARB's 45 g/MJ estimate. (GROWTHENERGY2_FF56-34)

> **Agency Response:** Due to LCFS credits and Federal tax credits for CCS projects, staff expects that some ethanol facilities will install CCS systems and supply ethanol to California. Staff expects the ethanol CIs could decline by about 25 gCO_2e/MJ based on estimated reductions from CCS. The actual magnitude of the reduction depends on the nature of CCS projects. To be eligible for CCS credits and hence lower CIs, CCS projects must meet the CCS permanence protocol requirements.

J-2.16. ***Transition to CA-GREET3.0***

J-2.16a. Comment: Recommended Action: Provide a timeline that demonstrates when a fuel pathway applicant can use CA GREET 2.0 versus CA GREET 3.0 and CARB's review and approval plan for each. For example, will CA-GREET 2.0 pathway applications pending as of 1/1/2019 continue to be reviewed and certified into 2019, or will applications in the queue be rejected? (ECOENGINEERS2_FF21-12)

> **Agency Response:** Please see Response J-2.18b. in Chapter IV.

J-2.16b. Comment: REG looks forward to updating of all ours fuel pathways under the new simplified Tier 1 model. We encourage staff to allow reapplications to begin at the start of 2019. We believe that a longer lead time will avoid the workload issues faced by companies and CARB staff alike which resulted from the rush of new pathways in 2016 which stemmed from re-adoption. (REG3_FF44-20)

> **Agency Response:** As proposed in section 95488(c), new pathway applications may be submitted using CA-GREET3.0 or the proposed Tier 1 Simplified CI Calculators beginning on January 1, 2019 (or the effective date of the amended rule, if not January 1, 2019).

J-2.16c. Comment: The CI for corn starch ethanol under CA GREET 3.0 contains a value for the electricity that is used in transportation and distribution with an emission factor developed using US average power, even though most such emissions are likely to be in California. (GROWTHENERGY2_FF56-35)

Agency Response: Please see Response J-2.18d from Chapter IV.

J-3. *Starch and Corn Fiber Ethanol*

J-3.1. Comment: The Tier 1 Simplified CI Calculator Instruction Manual (IM) is an excerpt from Attachment-C section C-3 of the CA-GREET3.0 Technical Support Documentation, and as presented in this manner RPMG understands this to be a part of the formal rulemaking package. While this inclusion in Technical Support Documentation does provide clear continuity of CA-GREET3.0 work conducted by staff, it also will make it difficult to modify or adjust the instructions on an as needed basis upon administering the LCFS program through additional or updated guidance after the conclusion of the rulemaking and final adoption. **Therefore, RPMG recommends updating the Instruction Manuals as suggested below, and to commit in the ISOR to releasing a timely Guidance Document as issues surface to ensure flexibility in modifying or updating the instructions in the future.**

The IM sates "all inputs selected and input by the applicant are subject to verification unless specifically exempted". Marking the importance of ensuring the parameters for inputs, conversion factors and exemptions outlined in the IM are clear and appropriate for utilization and on-going compliance with pathways. RPMG notes several areas outlined below in need of clarification in order to better determine the sufficiency of the instructions provided.

RPMG suggests the user-defined option for corn transport distance should be re-instated and maintained along with the 40-mile conditional default for all outside of California producers. There are three significant issues that arise if this user-defined option for corn transport is not re-instated as outlined here:

1. **There is now a substantial inconsistency between managing grain receipts for corn versus grain receipts for sorghum because one is allowed a user-defined option and the other is not.** Sorghum is generally received and processed in tandem with corn at a single facility, as no known facility operates on only sorghum in the United States. This would result in <u>the same single producer</u> being limited to only using a conditional default for their corn receipts, while allowing for user-defined tracking of actual sorghum receipts. It is impractical and unnecessary for a producer to manage two separate grain tracking methodologies for their Simplified CI Calculator inputs where the producer is not gaining an equal benefit for all recordkeeping efforts. In some cases the vender source of the grain may even be the same for both feedstocks. It is further a burden for validators and verifiers to have to incorporate a forced dual methodology into their review scope – again where there is no distinguishable purpose or benefit to the producer engaging those services.

Importantly, if a pathway applicant is able to develop a data collection method for demonstrating user-defined transport mileage for sorghum, it follows that the same applicant would be able to deploy the same resources to also track corn transport distances. **RPMG suggests the user-defined option for corn transport distance should be re-instated and maintained along with the 40-mile conditional default for all outside of California producers.**

2. In the 15-day package IM, corn transport by truck "outside of California" is listed as a conditional default of 40 miles. All other input options have been removed for these users. Conditions for use have been expressed in the IM section *Additional Details for Section 2* as:

   "for ethanol production facilities in one of nine corn growing states as specified by Argonne National Lab (ANL) known as 'corn belt states' (South Dakota, Minnesota, Iowa, Nebraska, Illinois, Michigan, Ohio, Indiana, and Wisconsin) a conditional default value of 40 miles for corn transport by HDD truck is available for selection. Sorghum transport for these regions is assigned a conditional default value of 80 miles by HDD truck. If the applicant selects this option (and is appropriate based on physical location of the ethanol production facility), transport distance will be subject to one-time validation during initial certification."

   This explicitly states that use of both the corn default and sorghum default is only applicable to producers located in the 9 "corn belt states." This creates an artificial barrier for applicable use of the Tier 1 Simplified CI Calculator for all starch ethanol producers outside this stated region. **It is RPMG's position that no condition or limitation of use to only "corn belt states" should be imposed for producers outside of California.** A 40-mile default is sufficiently conservative for most Midwest corn ethanol facilities based on provided research documenting an average transport radius of less than 20 miles.

3. **It also *implies* that if an applicant outside of the specified 9-state region selects the default (again the only present entry option) and somehow is granted use of the same, they *would* be subject to on-going verification of corn transport distance beyond initial validation – because they are not "specifically exempted."** Conditional Default is defined in section B. of the IM and states that "because each conditional default value must be based on reasonable assumptions and be sufficiently conservative to encourage use of site-specific values when feasible, conditional default values are subject to initial validation during the pathway certification process to confirm that the specified condition are met…" This is a markedly different approach from the original staff suggestion that standard defaults be exempted from verification requirements to reduce burden as documented in the staff discussion white paper released on 01-31-2017. There is further difference noted here of "conditional default" and "standard default", emphasizing a distinction that default values need not be "validated" or "verified" because they are "defaults." In the formal proposal defaults now carry conditions of use and are subject to initial validation. This

again is a break away from previous understanding of staff position seeking to overall reduce validation and verification burden for pathway applicants accepting default values. **This imposes an unnecessary burden to applicants, validators and CARB staff in preparing and verifying inputs that are established as conservative defaults for general use. It is RPMG's position that no condition or limitation of use to only "corn belt states" should be imposed for producers outside of California.** (RPMG3_FF41-4)

Agency Response: The Simplified CI Calculator has been updated to include a user-defined option for corn transportation to producers to supply fuel to California. With this update, the three significant issues raised by the commenter are, therefore, irrelevant. Given that transport distance for corn has been self-reported by ethanol producers since the inception of the program, this change offers an opportunity to verify actual feedstock transport distances for each pathway applicant. Staff would like to clarify that conditional default feedstock transport options for corn and sorghum are subject to validation, but not ongoing verification. Applicants selecting the user-defined transport option are subject to both validation and ongoing verification of those inputs.

If applicants experience challenges related to the use of Simplified CI Calculators (i.e., unit conversions, user-defined emission factors), staff is committed to releasing a Guidance Document to expedite applications by providing detailed responses to challenges experienced by applicants. Inclusion of the Simplified CI Calculators and the accompanying Instruction Manuals in the regulatory framework is to enable enforcement of all requirements stated in the Calculators and Instruction Manuals. Staff does not anticipate revisions to these Calculators or Manuals after the Board Hearing and final approval by the Office of Administrative Law.

J-3.2. Comment: Recommended Action: Assign GHG emissions associated with cellulase to all the ethanol produced from co-processing starch and corn-fiber. The cellulase is added to the corn mash, and this allocation will be consistent with that for other inputs such as electricity, natural gas, yeast, etc. (ECOENGINEERS2_FF21-13)

Agency Response: The cellulase enzyme is dosed only when the producer desires to produce cellulosic ethanol in addition to starch ethanol. It is, therefore, appropriate to allocate all GHG emissions associated with cellulase only to the cellulosic gallons produced.

J-3.3. Comment: Increase low carbon corn belt Ethanol by encouraging biogas or power from biogas to be transported to not otherwise adjacent but relatively close ethanol plants.

Don't lose these opportunities (MEG1_FF5-1)

Agency response: The current provision allows for the use of biogas or biogas derived electricity as process fuel in alternative fuel production. However, biogas

and biogas-derived electricity have to be supplied directly to the production facility. Indirect accounting for the use of such resources, such as book-and-claim methods, are not allowed to encourage integrated biorefineries that produce both biomethane and liquid biofuels.

J-3.4. Comment: Throughout section 2 of the simplified CI calculator there are descriptions present that indicate "if alternate approaches are used to [insert action], applicant must provide conversion factor used to report [insert calculator input and unit of measurement]." However, it is not specified where this alternate approach should be recorded. The natural location would be the Monitoring Plan (MP). However, the regulations at Section 95491.1 state that MPs are submitted to the Validator and to CARB for review for adequacy but the documents do not undergo any process of approval whereby a facility has assurance of its acceptability. In discussing with CARB staff, it was indicated that all sought alternative approaches should be discussed with staff prior to submitting applications on a case by case basis until or unless formal guidance would be provided in the future. This process appears to put a perpetual burden on staff that may be simply avoided. **RPMG recommends staff incorporate a process for acknowledging alternative approaches as they are received and reviewed in applicant MPs.** (RPMG3_FF41-4a)

Agency Response: The Simplified CI Calculators were developed after extensive consultations with stakeholders and all required inputs are expected to conform to most applicants. The option to account for "alternate approaches" was included to facilitate the use of Tier 1 Calculators for a few applicants where pathway inputs may not conform to those included in the calculators. It is suggested that applicants prepare a list of all "alternate approaches" and consult with staff before submitting an application. Given the likelihood that only a few applications will require the use of an "alternate approach", it is not expected to be a significant burden for all applicants. Discussions with staff and approval of "alternate approaches" prior to application submission is also expected to expedite application review. Based on number of "alternate approach" requests submitted effective January 1, 2019, staff will consider developing a guidance document to facilitate and expedite future applications which opt to use an "alternate approach".

J-3.5. Comment: The description for Field Name 2.4 Corn Received states "Input monthly total corn data (in bushels) <u>purchased</u> in this field for all 24 months of operation. While the corresponding entry field in the Simplified Calculator calls for <u>corn received</u> in field 2.4. RPMG notes that there may be a distinct difference in when a plant recognizes a <u>purchase</u> of grain and when that grain is physically <u>received</u> into inventory. **The IM should be edited to consistently reflect total corn data (in bushels) received.** (RPMG3_FF41-4b)

Agency Response: Staff proposed to replace "purchased" with "received" to ensure consistency between the Instruction Manual and the Simplified Calculator.

J-3.6. Comment: Section 2 additional detail for Co-products (Fields 2.14 to 2.40) states: "Facilities which report dry or modified DGS co-product streams will be required to report monthly total drying energy by installing dedicated energy meters in their facilities." **This statement should be qualified as applicable to applicants seeking segregated pathways per co-product streams and not to applicants seeking a single composite CI score.** (RPMG3_FF41-4c)

> **Agency Response:** For facilities that wish to apply for a composite CI score, there is no need to segregate NG use for drying by installing dedicated meters. Staff proposed to revise the text in Section 2 to imply that the statement is applicable only for applicants seeking segregated pathways for wet, modified and dry DGS.

J-3.7. Comment: IM and the Simplified Calculator Field Name for 3.8 is listed as "Electricity from Co-located Solar or Wind" in both places, however regulation section §95488.8(H) Renewable and Low-CI Process Energy states "must be directly consumed" not physically "co-located." **The Field Name for 3.8 should be modified to be consistent with §95488.8(H).** (RPMG3_FF41-4d)

> **Agency Response:** Staff updated this item to "Direct Electricity Use from Co-located Solar or Wind" in the Calculator and the Instruction Manual to be consistent with regulation section §95488.8(h). In §95488.8(h)(1)(B), it is specified that, "The generation equipment is directly connected through a dedicated line to a facility such that the generation and the load are both physically located on the customer side of the utility meter. The generation source may be grid-tied, but a dedicated connection must exist between the source and load."

J-3.8. Comment: Under any interpretation, the Proposed Amendments do not meet the standards set forth in Sections 38561(a) and 38562(e), as they continue to include inaccurate CI values for corn ethanol, cane ethanol, and electricity. (See Exhibit "A.") If a CI sends the wrong "signal" to downstream regulated parties, then the LCFS regulation will result in the use of pathways that may increase GHG emissions above the levels that would result if the best possible CI values had been assigned to various renewable-fuel pathways in the regulation. (See Exhibit "A.") While a small number of these issues were resolved through the Proposed Modifications, a review of the 15-Day Notice has revealed additional concerns with respect to the CI values proposed by CARB staff, which likewise would send the wrong "signals" and result in the greater use of higher CI fuels. (GROWTHENERGY2_FF56-13)

> **Agency Response:** Staff has carefully reviewed stakeholder comments and evaluated best available information and updated values for corn ethanol, cane ethanol and electricity in addition for other transportation fuels. Staff is committed to providing appropriate market signals to low carbon fuels and achieving proposed GHG reductions from the transportation sector.

J-4. *Sugarcane Ethanol*

J-4.1. *Refer to Previously Submitted Comments*

Comment: We recognize the effort of staff to try to make the pathway registration process more efficient and less complicated. For this reason, we urge the Board and ARB staff to carefully consider the letter of suggestions[6] UNICA delivered at the last Board meeting on April 23rd. We believe we have included valuable and important suggestions that need to be implemented in order to help California better capture the reality of the domestic sugarcane ethanol industry and reap the benefits of this low carbon intensive biofuel, so we urge you to take them into consideration before finalizing any adoption of amendments.

[6] UNICA's letter to CARB of April 23, 2018: https://bit.ly/2KJFEKO

(UNICA3_FF38-1)

Agency Response: See responses J-1.6, J-5.7, J-5.8, J-5.9, J-5.10, J-5.11, and J-5.12 in Chapter IV, in which the April 23rd comment letter is addressed.

J-4.2. *Mechanization*

J-4.2a. Comment: One input in the calculator that is of great importance to the Brazilian sugarcane sector is the mechanization input, given the advances and investments that the industry has made in this front in the last decade and the competitive advantages that set mills apart from their peers. We see that the version of the calculator posted online on June 20th does not allow for site-specific mechanization input and we urge staff to include this option before finalyzing the amendment adoption process.

According to the State-owned Brazilian Food Supply Company (CONAB in Portuguese), from the Ministry of Agriculture, Livestock and Food Supply (MAPA), the South-Central region, where the majority of UNICA members operate, has reached 95.6% of mechanization level in 2017/2018 crop year, compared to 28,5% one decade ago[8] . Indeed, this index is even higher according the Sugarcane Technology Center (CTC). Following its data, the mechanical harvesting in areas owned by mills, located in South Central region, reached 98% in the named season.

8 http://www.conab.gov.br/OlalaCMS/uploads/arquivos/17_08_24_08_59_54_boletim_cana_portugues_-_2o_lev_-_17-18.pdf (page 60)

It is important to mention that this is the region responsible for all the ethanol exported from Brazil to countries such as the United States, Japan and the European Union.

As CARB is aware, São Paulo state government, in partnership with UNICA and sugarcane growers association (ORPLANA), created in 2007 a Green Ethanol Protocol, a pioneer initiative that, among other commitments, eliminated pre-harvest field burning in 2017. According to the Environmental Secretary, 95% of all sugarcane processed in the São Paulo state is under the management of certified parties.[9] Since June 2017 this commitment has entered into a new phase, now called More Green Ethanol Protocol,

that continues to reiterate the pre-harvest field burning commitment, but includes the important commitment of restoring riparian vegetation around cane fields.

9 Slide 3 of the document: http://arquivos.ambiente.sp.gov.br/etanolverde/2017/06/etanol-verde-relatoriopreliminar-safra-16_17-site.pdf

Sugarcane Harvesting– Fast Mechanization Process in Brazil

Source: CONAB (National Supply Company, from the Brazilian Ministry of Agriculture, Livestock and Food Supply

As previously mentioned, industry has invested a great deal in mechanization in the sector in the last decade. Investments that helped sector reach a level of 57% of GHG emissions reduction from harvesting over the past 10 years (from 4.8 to 2.1 g CO_2eq/MJ of ethanol), considering the parameters given in Table 1. We believe there is strong evidence that the soil carbon stocks increase due to unburned mechanized harvesting[10]. Estimations from Figueiredo and La Scala Jr (2011)[11] indicate that the emissions in the mechanized harvesting are almost 1500 kg CO_2eq ha^{-1} $year^{-1}$ lower than those for the burned harvesting, since it leads to a soil carbon sequestration of more than 1170 kg CO_2eq ha^{-1} $year^{-1}$.

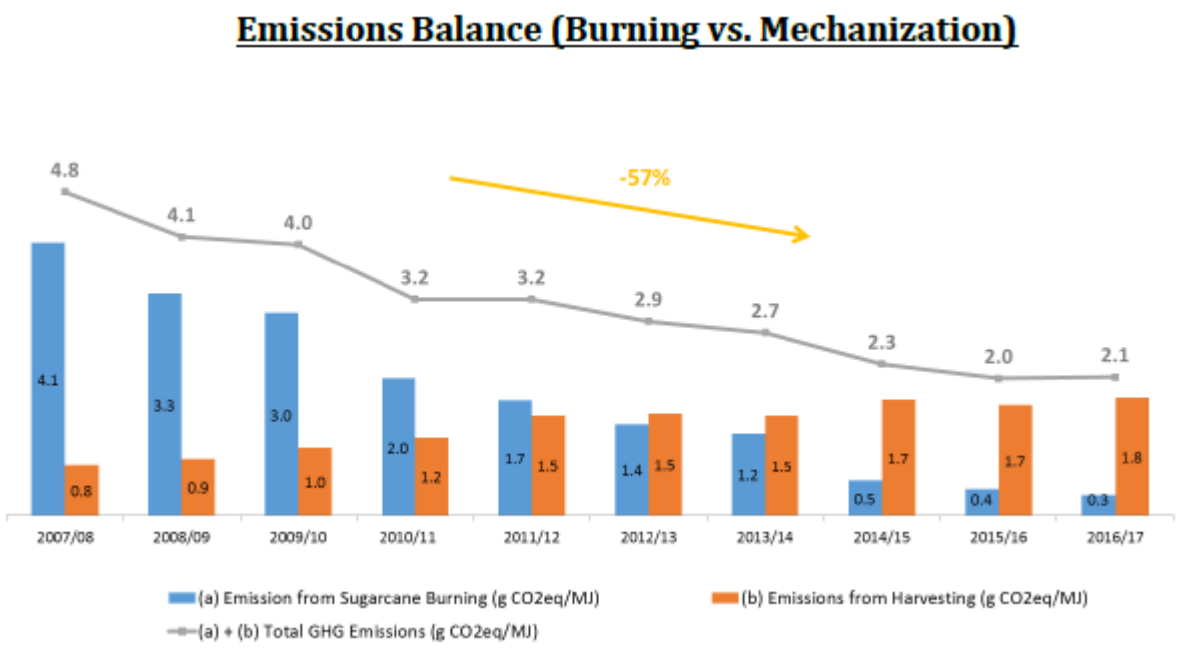
[10] Cerri, C. C., Galdos, M. V., Maia, S. M. F., Bernoux, M., Feigl, B. J., Powlson, D. and Cerri, C. E. P. European Journal of Soil Science; Special Issue: Soil Organic Matters; Volume 62, Issue 1, pages 23–28, February 2011

[11] Figueiredo EB, La Scala Jr N. Greenhouse gas balance due to the conversion of sugarcane areas from burned to green harvest in Brazil. Agriculture, Ecosystems and Environment 141 (2011): 77-85.

Table 1: Parameters used for the estimation of emissions balance between burned and mechanized harvesting

Parameter	Value/source
% Mechanized harvesting	CONAB
Sugarcane production	UNICA[12]
Sugar and ethanol production	UNICA[12]
Straw burning emissions	2.7 kg CH_4/t dry matter burnt[13]
	0.07 kg N_2O/t dry matter burnt[13]
Straw to cane stalk ratio	140 kg (dry basis) per tonne of stalk[14]
Harvester's diesel consumption	74 L/ha [15]
Life cycle diesel emissions	83.8 g CO_2eq/MJ [16]

[12] http://www.unicadata.com.br/
[13] IPCC 2006, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Prepared by the National Greenhouse Gas Inventories Programme, Eggleston H.S., Buendia L., Miwa K., Ngara T. and Tanabe K. (eds). Published: IGES, Japan.
[14] Hassuani SJ, Leal MRLV, Macedo IC. Biomass power generation: sugar cane bagasse and trash. Piracicaba: PNUD Brasil and Centro de Tecnologia Canavieira; 2005.
[15] Adapted from Macedo IC, Seabra JEA, Silva JEAR. Green house gases emissions in the production and use of ethanol from sugarcane in Brazil: The 2005/2006 averages and a prediction for 2020. Biomass and Bioenergy 32 (2008): 582-595.
[16] European Parliament and Council of the European Union, Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009, on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC, Official Journal of the European Union of 5 June (2009).



In the CI calculator for sugarcane ethanol, CARB proposes two default values for sugarcane mechanization for Brazil: 80% for São Paulo state and 65% for other states in the Center-South region. By choosing to use the default values, mills will not need to have this input verified. UNICA will probably have members who will be satisfied using the default value, however, the vast majority of our members located in Sao Paulo, who have nearly all of its sugarcane harvesting mechanized, and a considerable number of members in other states, prefer to prove that they are at highest level of mechanization, as abovementioned reported by CONAB and CTC.

For this effect, UNICA would like to request, once again, that CARB includes an option for self-declared mechanization percentage in the CI calculator, we are aware that mills opting for it will have its data and its mill audited by a CARB authorized third party verification body. In the April 23rd letter[17] to CARB, Exhibit A, UNICA has suggested an outline for proving mechanization levels in Brazil, we encourage staff analyze it and make a decision on the process in order to include the site-specific input as soon as possible.

17 April 23, 2018 UNICA's letter to CARB, Exhibit A, page 12: https://bit.ly/2KJFEKO

(UNICA3_FF38-3)

Agency Response: Please see Response J-5.9 in Chapter IV.

J-4.2b. Comment: UNICA member mills, who represent the vast majority of Brazilian mills registered with CARB, are highly sophisticated enterprises who invest a great deal in the automatization of their agricultural and industrial processes. Third party verifying bodies in Brazil have, for years, audited mills' systems for certification schemes like the Bonsucro, EPA's RFS program and the LCFS in itself. We encourage CARB staff to continue to reach out to verification companies in Brazil, as well as to regulatory agencies in the country, in order to clarify doubts or misunderstanding regarding the automatized systems used by sugarcane mills.

We believe providing these options are not only the best way to capture the reality of sugarcane mechanization practices in Brazil, but it is also the fairest approach to allow Brazilian ethanol to compete in the Californian market. (UNICA3-FF38-5)

Agency Response: Staff reiterates the points made in Response J-5.9 in Chapter IV regarding proposed crediting of mechanized harvesting under the LCFS. Staff continues to reach out to certification schemes regarding verification of mechanized harvesting. Staff encourages stakeholders to utilize the standard mechanization options provided in the Tier 1 Simplified CI Calculator for Sugarcane-derived Ethanol.

J-4.3. *Carbon Intensity Score for Sugarcane Ethanol*

J-4.3a. Comment: We commend CARB for its efforts to simplify and make the LCFS registration process more efficient. We want to make sure that the amendments proposed will indeed have these consequences and will allow for a closer-to-reality carbon intensity number for sugarcane ethanol. We would like to see more volumes of low carbon Brazilian sugarcane ethanol entering the Californian market. We urge

CARB to consider our suggestions and ensure that sugarcane ethanol is fairly scored in the GREET-CA 3.0 modeling and that Californian consumers reap the benefits of sugarcane ethanol. (UNICA3_FF38-6)

Agency Response: Please see Response J-5.12 in Chapter IV.

J-4.3b. Multiple Comments: ***Carbon Intensity Score for Sugarcane Ethanol should be Revised***

Comment: Moreover, despite the extensive comments previously provided for cane ethanol, which demonstrated the CI for cane was understated by approximately 5.5 g/MJ, the Proposed Modifications contain no revisions to correct this erroneous CI value. (*Cf.* April 27, 2018, Comments at 12-15.) (GROWTHENERGY2_FF56-16)

Comment: We made a number of comments on the carbon intensity of the sugarcane pathway, which were not adopted in the 15-day notice. Implementation of these suggestions would have increased the CI of sugarcane ethanol by about 5.5 g/MJ. To ensure the Proposed Amendments are based on the best available scientific information, our suggested changes should be implemented. (GROWTHENERGY2_FF56-62)

Agency response: Staff has updated the nitrogen content of sugarcane biomass to correct an error in the Argonne GREET1_2016 model. The updated value reflects an average from the various studies referenced in the GREET supporting document. In addition, staff has updated the N_2O emission factor for cane pathways to be consistent with corn ethanol pathways.

J-4.3c. Comment: The CI for sugarcane is understated because the nitrogen content of biomass and fertilizer for sugarcane are far higher than estimated by CARB. (GROWTHENERGY2_FF56-36)

Agency Response: See response to GROWTHENERGY1_B4-23e in the Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

J-4.4. ***Truck Transport***

Comment: CA GREET 3.0 uses the same emission factor for truck transport in Brazil and California, even though Brazil should be higher. (GROWTHENERGY2_FF56-37)

Agency Response: See response to GROWTHENERGY1_B4-54f in the Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

J-5. *Biodiesel and Renewable Diesel*

J-5.1. Multiple Comments: *Biodiesel/Renewable Diesel Simplified CI Calculator*

Comment: The BD/RD calculator has most of the previous errors removed, but there are still some issues that remain, which lead to incorrect results.

There are also some inconsistencies in how the same data is moved from the EF sheet to the calculation sheets. For example, on the Tallow tabs, cell G11 is zero and the calculator is pulling the standard value from the emission factors sheet, whereas other feedstocks move from the emission factor sheet to G11 and then into the calculations.

The most serious error is on the RD Production sheet in cell M158. This cell does not have an equivalent value on the previous version of the calculator. Zeroing it out in the current version gets the RD production emissions much more in line with the previous version. The previous version had those rows there but nothing in column M. The value in this cell should be removed as it is not clear what it is trying to calculate and clearly shouldn't be there.

On the canola sheet, the standard value for oil production (G11) is ~0.27 instead of the ~118 it should be.

BD Production!J101 points to corn oil production, not UCO oil production. It should be changed to reference EF Tables!C44.

BD Production!J122 points to a tallow oil production value that is not equal to the one on RD Production. This is just more inconsistency where all oil production values really should be aiming at the same place. Setting it to equal to the formula used on RD Production J127 will bring the CI value for that stage in line.

On RD Production: M81:M84 use Fuel_Specs!$D$79 which is for soy oil, they should use Fuel_Specs!$D$81 instead. Similarly, on BD production M70:M85 uses the B79 instead of B81, Although these do not impact the results.

There is a discrepancy between BD and RD tallow is that BD tallow has an additional value for raw tallow transport, which is not included in the RD calculation.

The distance that feedstock is moved by heavy truck is hardcoded in most cases. For canola, it is moved 40 miles if being crushed for an oil that will become BD and 50 miles if being crushed for an oil that will become RD. They should be set to the same distance. (NBBCABA3_FF4-15)

Comment: Also related to the proposed GREET 3.0 model are revisions to the renewable diesel production emission calculation methodology. Specifically, the spreadsheet model ("RD Production" sheet, cell M158), introduces a new factor which substantially increases the calculated production emissions from renewable diesel, with the effect of increasing the RD CI by more than 11 g/MJ. There is no analogous factor in the prior version of the GREET model, and the literature CARB has released to-date

does not discuss the origin and/or necessity of this factor. Consequently, we contend that this increase constitutes an error in the GREET 3.0 model and should be corrected. However, to the extent that CARB believes the model to be accurate, CARB should provide, for public review and comment, the scientific justification for increasing the modeled production emissions based solely on a ratio of energy content between naphtha and renewable diesel. (DGD3_FF25-2)

> **Agency Response:** Staff corrected this error in the BD/RD Simplified CI Calculator to address these comments.

J-5.2. *Vessel Emission Factors*

Comment: We have noticed that the vessel emission factors contained in the simplified model for biodiesel and renewable diesel appear incorrect. The correct factors based on our own math appear to be 0.0735106 and 0.1150932 for renewable diesel and biodiesel respectively. The factors contained in cells 'EF Table'!C50 and 'EF Table'!C59 seem to be calculated incorrectly from CA-GREET 3.0. This error appears due to table which looks mislabeled. The erroneously labeled tables are contained in the T&D tab of CA GREET 3.0. We believe The cells 'T&D'!GX152 & 'T&D'!GS152 need to be switched to avoid confusion in the future. When the labels are switched and the appropriate density is used to convert from tons to gallons is applied, our math above is validated. (REG3_FF44-24)

> **Agency Response:** Staff corrected pointing errors for ocean tanker emissions for biodiesel and renewable diesel in the T&D tab in CA-GREET3.0. However, staff did not switch labels in cells 'T&D'!GX152 and 'T&D'!GS152 because the original calculation of other transportation modes for biodiesel and renewable diesel were correct. All emission factors in the latest Simplified CI Calculator were updated accordingly.

J-5.3. *Co-Products used as a Process Fuel*

Comment: The Tier 1 Simplified CI Calculator for Biodiesel and Renewable Diesel states that If part or all of the co-products are used as process fuel, co-product credit will not be offered.

<u>Recommended Action:</u> Change the above to state, "If part or all of the co-products are used as process fuel, co-product credit will not be offered for the fraction that are used as process fuel (the other fraction that is not used as process fuel should still get co-product credit)." (ECOENGINEERS2_FF21-17)

> **Agency Response:** The suggested modification is incorporated in the Tier 1 Simplified CI Calculator for Biodiesel and Renewable Diesel. Staff proposed to modify the text as suggested above with a requirement for the applicant to provide evidence of final disposition of quantities of co-products for which co-product is included.

J-6. *Simplified CI Calculator for Biomethane from Anaerobic Digestion of Organic Waste*

J-6.1. Comment: Summary of Specific Concern

AD-based pathways, whether for food/green waste, or animal waste, face a unique risk under the proposed verification structure. Much of the carbon intensity reductions attributed to these pathways stem from avoided emissions credits (from landfills, wastewater lagoons, etc) and are fixed based on the mass of feedstock input into the facility. However, the amount of biogas produced by these facilities is a function of the efficiency of the facility and it is possible for the facility to produce more biogas than provided for in the avoided emissions credits. Biogas produced in excess of the volumes assumed in the avoided emissions credits will not receive the benefit of these credits and will increase the average carbon intensity of the biogas produced by the facility. Consequently, an AD facility that improves its biogas production efficiency would increase its CI value. During verification, the facility operator could be subject to significant penalties as the operating CI would be higher than the certified CI. It is unreasonable to subject a facility operator to penalties stemming from improved operating efficiencies, particularly under a carbon reduction program such as the LCFS, and is contrary to State goals for renewable fuel production.

In cases where biogas production efficiencies decrease, facility operators are likely to see lower operating CIs and lower biogas output. The facility operator would not be able to claim the additional credits associated with the lower operating CI but would realize reduced credit generation from the lower biogas output. Consequently, the current program structure could penalize biogas facility operators for increases or decreases in production efficiency.

Recommendation

TWC recommends ARB clarify that: 1) increases in the operational CI of a facility, owing to higher biogas production efficiencies than were estimated in the facility's pathway application, do not constitute Material Misstatements as defined in the proposed regulation and, 2) fines or other penalties would not be assessed to the pathway holder based on the higher operational CI.

TWC also believes that ARB should continue to move the LCFS program toward a structure that allows for full true ups of credits generated by biogas projects. This structure would address the specific concern of facility efficiency impacts and verification risk discussed above. Further, such a structure would allow biogas projects to claim all credits actually generated and reduce risk to the project developer, thereby helping to enable development of these projects. (TWC1_FF48-2)

> **Agency Response:** If large variabilities in CI result directly from situations as stated by the commenter resulting in non-compliance with the LCFS certified CIs, fuel producers should petition the Executive Officer to waive penalties associated with non-compliance. The Executive Officer's ruling on this matter shall be final

and not subject to further appeal. However, credit adjustments related to exceedances in certified CIs shall conform to requirements in the regulation.

J-6.2. Comment: Summary of Specific Concern

The current Tier 1 calculator implements three categories of organic waste; food waste, green waste, and other organic waste. While some feedstocks clearly fit within the food waste or green waste categories, the proper categorization of other feedstocks is unclear. For example, a food processing facility may generate feedstock streams that are composed primarily of simple sugars and carbohydrates consistent with "food waste", and additionally generate feedstock streams that have high cellulosic content consistent with "green waste." Lacking clear definitions of these terms, applicants may develop projects based on incorrectly classified feedstocks, only to face significant changes to their pathway during the approval process or face significant enforcement risks during the verification process.

Recommendation

ARB can provide a unified input structure for all organic waste streams by using the structure currently implemented for the "Other Organic Waste" feedstock. Under this structure, the user would be required to supply DOC, DOCf, landfill diversion, and composting rates for all feedstock mixes. Reasonable input values for feedstocks that ARB currently terms "food waste" and "green waste" can be provided as part of the calculator's technical documentation, effectively replicating the function of the existing food waste and green waste inputs in the model.

To the extent that ARB continues to classify feedstocks using the terms "food waste," "green waste," and "other organic waste," TWC recommends that ARB provide additional technical guidance to applicants that defines these terms based on feedstock compositions or other unambiguous metrics. (TWC1_FF48-3)

Agency Response: Staff replaced the names of categories "food waste" and "green waste" with "Food Scraps" and "Urban Landscaping Waste", respectively. The characterization and possible sources of these two waste categories have been detailed in the calculator and its accompanying Instruction Manual. Due to the non-homogenized physical and chemical properties of "Food Scraps" and "Urban Landscaping Waste", staff believes these two calculation tabs provide a simple, general approach for projects that separate food scraps from MSW or divert urban landscaping waste collection to anaerobic digestion. The factors provided in the individual tabs are supported by literature (see references in the Instruction Manual) and represent average properties of these waste categories. If feedstocks cannot be categorized using the guidelines provided, applicants may request appropriate classification by the Executive Officer by submitting supporting information. Additional information regarding "Other Organic Waste" is available in the OW tab of the Simplified CI Calculator and the corresponding Instruction Manual.

J-6.3. Comment: Summary of Specific Concern

Under the current calculator framework, ARB estimates the methane generation potential of the feedstocks using DOC and DOCf values. These values are predetermined for the food waste and green waste categories. Along with predetermined values for landfill diversion and composting, the calculator fixes the potential "landfill credit" for avoided methane emissions for these two feedstock categories. For other organic wastes, the process is much more ambiguous. The available technical guidance from ARB does not indicate how an applicant should expect to assess the DOC and DOCf values for their feedstocks. Additionally, it is not clear whether these values would be subject to the third-party verification process.

Because of these ambiguities, potential project developers with feedstock streams that are not classified as "food waste" or "green waste" may be discouraged from using the Tier 1 calculator process and could face additional verification risks. The DOC and DOCf values used by Staff for the food waste and green waste feedstocks are average values for a broad range of waste streams and not subject to subsequent verification. Hence, it is reasonable to assume that DOC and DOCf values approved by ARB for a specific project under the "Other Organic Waste" category would be at least as accurate as the predetermined values assigned to food waste and green waste, and should also be exempt from the verification process.

Recommendation

We recommend that Staff provide additional guidance on the process that applicants should use to assess the DOC and DOCf values for their feedstocks. We also recommend that the values, once approved by ARB, would not be subject to the third-party verification process. (TWC1_FF48-4)

> **Agency Response:** Staff provided DOC and/or DOCf values for additional common organic materials likely to be used as feedstocks for biogas production. Staff also provided guidance on calculating DOC and DOCf factors if the feedstock cannot be categorized as any one of the organic materials listed in the calculator. These values and guidance are consistent with the methodologies used by either Argonne or the Code of Federal Regulations. All analytical test results and other data used in the determination of each factor must meet the requirements of the monitoring plan for entities required to validate or verify pursuant to sections 95491.1(c). Given that physical and chemical characteristics of some organic materials may change or fluctuate significantly due to time, sources, upstream process efficiency and feedstock quality, staff believes that site-specific (user-defined) DOC and DOCf values of these materials should be monitored and verified to ensure the accuracy of the pathway CI. Note that the use of default DOC and DOCf values provided in the calculator do not require verification, since they are not site-specific values.

J-6.4. Comment: 1. Input 2.8, "Moisture Content of Other Organic Wastes," is no longer used as the throughput, DOC, and DOCf values are all provided on a wet basis. This input should be removed. (TWC1_FF48-5)

> **Agency Response:** If a specific feedstock cannot be binned into any of the categories listed in the Instruction Manual for the Simplified CI Calculator for Biomethane from Anaerobic Digestion of Organic Waste, or the applicant cannot perform the necessary analytical tests to determine the DOC of a feedstock directly, the moisture content and the volatile solids content of such feedstock can be used to estimate its DOC factor. If an applicant chooses to use an estimation method, the reported moisture results for a given feedstock must meet the requirements of the monitoring plan for entities required to validate or verify pursuant to sections 95491.1(c).

J-6.5. Comment: 2. Tailpipe N_2O emissions for NGVs, calculated in cells 'Reference!B57' and 'Reference!D57' should include a credit for avoided natural gas flaring, as is done with regard to tailpipe methane emissions. (TWC1_FF48-6)

> **Agency Response:** Staff corrected this to be consistent with the landfill to biomethane pathway.

J-6.6. Comment: 3. Various cells in the calculator have references to external spreadsheets, and should reference the equivalent internal worksheets. For example, 'Reference!B56'. (TWC1_FF48-7)

> **Agency Response:** Staff corrected these issues in the calculator in response to this comment.

J-6.7. Comment: 1. Include biogenic CO2 while calculating tailpipe emissions (Cell I102 and I103) in RNG tab. Because the fuel is taking avoided methane emission credits from landfill diversion, the tailpipe emissions calculations should be similar to those in the dairy and swine manure biomethane calculator. (ECOENGINEERS2_FF21-14, BLUESOURCE1_FF70-11)

> **Agency Response:** There are different ways of GHG accounting with the same outcome. As suggested above, one can perform full carbon accounting by including methane avoided credits for capturing methane that would otherwise be vented to the atmosphere and also including tailpipe biogenic emissions. The other approach is to consider the methane avoided credits and adjust these credits to reflect an equivalent amount of biogenic CO_2 emissions. Since the latter approach simplifies the calculation, staff proposed to adopt the latter approach in the Simplified CI Calculator.

J-6.8. Multiple Comments: ***User-Defined Moisture Content***

Comment: 2. Provide an option for user-defined moisture content. Currently, default moisture of food waste is set at 72% and no user-defined values are currently allowed;

therefore, if the actual moisture content of food waste is different from 72%, the final CI will be over or under estimated. (ECOENGINEERS2_FF21-15)

Comment: 2. Provide an option for user-defined moisture content. Currently, default moisture of food waste is set at 72% and no user-defined values are currently; therefore, if the actual moisture content of food waste is different from 72%, the final CI will be over or under estimated. (BLUESOURCE1_FF70-12)

> **Agency Response:** The characterization and possible sources of the "Food Scraps" (formerly "food waste") and the "Urban Landscaping Waste" (formerly "green waste") have been detailed in the CI Calculator and its accompanying Instruction Manual. To expedite review and processing of applications and to limit verification burden, staff proposed to use a standard value for a feedstock which can be classified as "food scrap." If the characteristics of a feedstock significantly deviate from the "Food Scraps" or "Urban Landscaping Waste," applicant should use the "Other Organic Waste" category and follow the guidelines provided in the OW tab and the corresponding Instruction Manual to conduct the calculation.

J-6.9. Comment: Recommended Action: Please clarify how monthly weighted methane content (%) in the digester gas should be calculated for all proposed biomethane calculators and what CARB staff will need for as supporting documents. (ECOENGINEERS2_FF21-16)

> **Agency Response:** Methane content in biogas is typically measured continuously using a gas chromatograph by project operators. Likewise, volumes of dry biogas produced are recorded continuously using appropriate flow meters. The monthly weighted methane content is calculated using methane concentrations and corresponding biogas volumes. The supporting documents for submission include daily measurements of biogas volumes and corresponding methane concentrations.

J-6.10. Comment: RNG Coalition appreciates the inclusion of simplified Tier 1 CI Calculators for Wastewater Sludge, Dairy and Swine Manure and Food, Green, and Other Organic Waste in the proposed modifications. However, we are concerned that the process of revealing the Dairy and Swine Manure and Food, Green, and Other Organic Waste calculators is beyond the scope of the 15-day package and thus provides inadequate opportunity to evaluate. These are highly complex mechanisms that will take more time for us to review. Initial feedback we have received indicates that the Food, Green, and Other Organic Waste calculator results in material deviations, such as previously negative CI scores that will now be positive, that require additional time for our members to review the extensive associated modeling. **Therefore, we respectfully ask for sufficient opportunity, at least two to three weeks, to review the calculators and discuss with staff.** (RNGC3_FF46-4)

> **Agency Response:** Although the life cycle methodology in the Dairy Biomethane Calculator is complex, the approach is identical to the dairy

biomethane pathway certified in Q1, 2017 using CA-GREET2.0. Therefore, the comment period provided for public review and comments is considered adequate for this pathway.

The life cycle approach in the Wastewater biomethane and Food Scraps/Green Waste/Organic Residue are similar and relatively straight-forward. Except for the avoided methane credit for the latter, both Calculators are similar to the Simplified CI Calculator for Biomethane from North American Landfills, published during the 45-day comment period. Therefore, the comment period provided for public review and comments is considered adequate for this pathway.

J-7. *Dairy Biomethane*

J-7.1. Comment: b. We suggest this Tier 1 Biomethane Calculator, (or more likely a new, separate Tier 1 calculator) should account for the use of biomethane in the production of ethanol, the most likely near-term use of California dairy digester cluster biogas. In fact, ARB has already produced a Tier 1 Simplified CI Calculator for Starch and Corn-Fiber Ethanol. This tool could be modified to include an "Avoided Emissions" tab using the same manure methane emissions calculations as exist in the tab of the same name in the Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure. (MEW1_FF40-5)

Agency Response: There is no need for a separate Tier 1 Calculator for the use of dairy biogas as a process fuel in ethanol plants. The Simplified CI Calculator for starch ethanol includes a field for the use of biogas as a process fuel. Since the emission factor for this input is a user-specific value, applicants may consult staff in developing a biogas-specific emission factor. This will facilitate the use of dairy biogas as a process fuel in an ethanol production facility.

J-7.2. Comment: We applaud the work by ARB is the creation of the Tier 1 Simplified Calculators. As mention is preceding comments, we would like the ability to claim avoided dairy emissions for more than use in CNG and LNG. It is our thought that all of the simplified calculators include an "Avoided Emission" tab using the same manure methane emissions calculation as exist in the 95488.3 (b)(7) "Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure". (CRF2_FF42-7)

Agency Response: Applicants can claim emissions reduction (including avoided methane credits) if biomethane is used either as process fuel or feedstock for fuel production. When used as a process fuel, book-and-claim accounting is not permitted and the biomethane has to be supplied directly to the production facility. Since it is not possible to model all possible combinations of renewable fuel use in Tier 1 calculators, staff did not include an option for the use of biomethane as a process fuel in the Tier 1 Calculators except for the starch ethanol Calculator (primarily because such projects currently exist in starch

ethanol plants). If biomethane (with or without avoided methane attributes) is used as a process fuel, applicants may apply using a Tier 2 framework.

J-7.3. Comment: c. In light of the preceding comments, we think it would be more appropriate to rename the calculator listed in 95488.3(b)(7) to be "Simplified CI Calculator for Biomethane Compressed Natural Gas/Liquid Natural Gas from Anaerobic Digestion of Dairy and Swine Manure, since various other uses of biomethane can and will be employed. (MEW1_FF40-6)

Agency Response: Staff maintained the existing name of the Calculator but revised the definition of biomethane. Please refer to Responses C-1.4b through C-1.4d, Definition of "Biomethane," in Chapter IV regarding the revised definition, and Response J-7.8 in this chapter regarding the use of biomethane as a process fuel.

J-7.4. Comment: d. Finally, biomethane CNG/LNG should not be the only uses of biomethane that are afforded temporary pathway CI values. Other uses such as ethanol (the most likely near-term use of dairy cluster biogas) and hydrogen (a major goal of ARB) should get the same benefit when using biomethane as an input. Any transportation fuel pathway that uses biomethane and is eligible to claim avoided methane emissions benefits should be eligible for as assumed -150 CI on all biogas used in that pathway. (MEW1_FF40-10)

Agency Response: Temporary CIs are offered only to pathways where a fuel is used directly as a transportation fuel. Therefore, the use of temporary CIs (i.e., a -150 g/MJ for dairy biomethane) will not be offered for biomethane used as a feedstock or as a process fuel.

J-7.5. Comment: Summary of Specific Concern

The carbon intensity scores for anaerobic digester (AD) based biogas pathways are strongly impacted by the assumed avoided fate of the feedstock. In particular, diversion of waste streams from landfills generate substantial methane reductions that are appropriately credited to the AD project pathway. Because these credits are a significant portion of the total CI for a project, changes to these credits can have a dramatic impact on revenue generation and financial viability of the project. Hence, reasonable and stable assumptions for landfill diversion credits are critical to the development of AD projects for diversion of organics from landfills.

A number of state-level policies, including SB 1383, AB 1826, and the State's Short-Lived Climate Pollutant Reduction Strategy call for increased diversion of organics from landfills. In particular, AB 1826 calls for 50% diversion of organic wastes by 2020 and SB 1383 calls for 75% diversion by 2025. Anaerobic digester projects are an important approach to achieving these goals. Consequently, the implementation of organics diversion requirements should not be counted against such projects when assessing landfill diversion credits. Indeed, doing so would undermine the ability of the state to achieve its diversion goals and would leave organics in landfills.

TWC also notes that AD projects are currently being considered for waste streams that are not being landfilled today, but will be landfilled in the near-term, if AD projects are not constructed to accept the waste. This is of particular concern for food and agricultural waste streams where the current end use is for animal feed. This market is changing rapidly and quickly becoming saturated with available feedstocks. Consequently, many food and agricultural waste producers will no longer be able to send feedstocks to animal feed end uses and could begin landfilling the material. AD projects represent an alternative strategy that avoids landfilling, but these projects are unlikely to be constructed if the LCFS program does not recognize landfilling as the avoided fate of these materials.

Recommendation

ARB should not discount the "% to Landfill" diversion fate assumed for AD pathways based on landfilling diversion policies or regulations as AD projects are one of the few strategies to enable these diversion goals. Additionally, ARB should allow applicants to claim landfill diversion credits for a waste stream where the applicant can demonstrate that the waste stream has little or no monetary value in its traditional end uses. (TWC1_FF48-1)

> **Agency Response:** Staff agree with the commenter that reasonable and stable assumptions for landfill diversion credits are critical to the development of AD projects for diversion of organics from landfills. In the life cycle analysis of fuel pathways in the LCFS program, avoided methane crediting is considered if and only if such reductions are additional to mandated requirements from existing regulations, industry-wide standards or business practices. For dairy and swine or organic waste biomethane projects operational before any regulatory requirements (i.e., SB 1383, AB 1826) related to organics diversion become effective, the LCFS program offers a 10-year window from original inception of the project for which methane avoided considerations will be offered, pursuant to section 95488.9(f). Projects operational after inception of mandatory regulatory requirements will not be offered avoided methane credits.
>
> Since methane avoided credits are considered only for projects which meet the regulatory additionality criteria, an appropriate diversion ratio is a critical metric for such pathways. The diversion ratio is also likely to be project-specific. It will be incumbent upon the applicant to demonstrate to the Executive Officer evidence or data to consider a specific diversion ratio for any feedstock used in the applicant's fuel pathway.

J-7.6. Comment: The development of a Tier 1 Simplified Calculator for dairy biomethane projects will be extremely helpful for producers developing these projects for the California market. DTEBE thanks CARB for developing this calculator to help facilitate the participation of dairy biomethane projects in the LCFS program. After reviewing the Tier 1 calculator, DTEBE suggests that the calculator be modified to account for the transportation of processed RNG by CNG trailer. The Tier 1 calculator currently accounts for the transportation of feedstock manure by truck, but many RNG

projects on small farms will transport RNG by CNG trailer after it has been processed. Adding this functionality in the Tier 1 calculator will allow projects that utilize CNG trucking to use this simplified calculator to register as a Tier 1 pathway. (DTEBE2_FF20-7)

> **Agency Response:** All applications certified for biomethane in the LCFS have either used pipeline transport or direct-use at an on-site filling station. Since Tier 1 Calculators are expected to model operation of typical operating projects, only the options stated above are included in this Calculator. Inclusion of emission factors for fuel transport by truck requires a comprehensive review of literature to account for life cycle impacts of transporting renewable natural gas by heavy-duty trucks, tube trailers or other modes of transport. If an applicant can meet the substantiality threshold requirements of section 95488.9(a), a Tier 2 option could be considered for project operators utilizing novel modes of transport including the option stated by the commenter.

J-7.7. Comment: 6. As implied by our foregoing comments, we are eager to find an acceptable way to avoid being penalized for being the first dairy cluster project in California. Because of inherent delays in arranging for gas pipeline injection, the first 6-8 dairy digesters in the first dairy digester cluster in California are <u>not</u> likely to produce CNG/LNG vehicle fuel. Rather, they will initially supply their biogas/biomethane as an input to make low carbon ethanol and/or biodiesel at the Calgren Renewable Fuels facility near Pixley, and only later transition to CNG fueling. There are no other dairy digesters clusters anywhere in the state likely to produce CNG fuel in the next 12 month. Thus it is important to recognize that while converting dairy digester gas to CNG is a long-term goal, the near-term use of dairy digester gas in ethanol production and biodiesel production is an important first step.

a. One way to do this might be to rename the calculator listed in 95488.3(b) (7) to be “Simplified CI Calculator for <u>Biomethane Compressed Natural Gas/Liquid Natural Gas</u> from Anaerobic Digestion of Dairy and Swine Manure, since various other uses of biomethane can and will be employed. Any alternative that works is acceptable.

b. Through our affiliate, Calgren Dairy Fuels, we have signed up fifteen dairies and are in advanced discussions with others. While the actual number of digesters built may be less (one dairy was sold and two other dairies will share a digester), the point is that new digesters will be serially added over an extended period of time. Likewise, CNG refueling stations will be added serially, with at least one new station contemplated to be built next door to our biogas upgrade facility. We appreciate that ARB will need at least ninety days of data for each of the new digesters. Finding an acceptable way to avoid losing the carbon credits during those data collection periods is important. We believe that preserving the maximum amount of regulator flexibility will be vitally important.

c. In addition to granting new dairy digesters a conservative temporary CI value of -150, we think ARB should be careful to preserve the concept that verification will only occur over twenty-four month periods and only compare claimed carbon

savings to actual carbon savings. As noted earlier, dairy clusters typically involve ambient digesters that are subject to substantial seasonal swings. This is often a detriment. However, with appropriate regulatory flexibility and verification over two whole seasons, dairy clusters may someday benefit by "smoothing out" high production periods and low production periods. (CRF2_FF42-8)

Agency Response: The commenter is correct that all Simplified CI Calculators for biomethane are designed to calculate CI results for biomethane used directly in vehicles as CNG and LNG. However, the Simplified CI Calculator for Starch and Fiber Ethanol is designed to include a user-defined emission factor for biomethane used as process energy, which can be determined using one of the biomethane calculators.

Staff is committed to evaluating all submitted pathway applications, including Calgren's applications, in a timely manner and we expect that the availability of the Temporary CI and the provisional application process will help to ensure that emission reductions are accurately counted and there is minimal loss of crediting resulting from the data collection time period.

Staff understands that there are seasonal swings in CIs for dairy and swine manure biomethane projects and is committed to evaluating CI conformance on a period of no less than 12 months initially, and 24 months once that period is available.

J-7.8. *Biomethane as a Process Fuel*

Comment: a. We appreciate the addition of the Tier 1 Simplified Calculators in 95488.3 (b), and in particular the Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure. However, this tool appears to be designed only for use of biomethane as a compressed natural gas or liquid natural gas vehicle fuel. As we have pointed out in our first comment above, this definition of "biomethane" could greatly restrict the uses of dairy digester gas. The first 6-8 dairy digesters in the first dairy digester cluster in California are all <u>not</u> producing CNG vehicle fuel. Rather, they will initially supply their biomethane as an input to make low carbon ethanol at the Calgren Renewable Fuels facility near Pixley, and only later transition to CNG fueling. There are no other dairy digesters clusters anywhere in the state likely to produce CNG fuel in the next 12 months, and so it is puzzling to see ARB's focus on CNG when the near-term use of dairy digester gas is ethanol production. (MEW1_FF40-4)

Agency Response: The commenter is correct that Tier 1 Simplified CI Calculator for Anaerobic Digestion of Dairy and Swine Manure is used to calculate the CI of biomethane used in vehicles as CNG, LNG, or L-CNG. If this biomethane is used as a process fuel in a starch ethanol facility, it can be modeled using the Tier 1 Simplified Calculator for Starch and Fiber Ethanol. For situations such as several digesters coming online on a staggered schedule, applicants may have to pursue a Tier 2 pathway.

Please also refer to Responses C-1.4b through C-1.4d, Definition of "Biomethane" in Chapter IV.

J-8. *Wastewater Biomethane*

J-8.1. Comment: 2. Section 95488.9(f)(2) States that: "A fuel pathway that utilizes an organic material may be certified with a CI that reflects the reduction of greenhouse gas emissions achieved by the **voluntary** diversion from decomposition in a landfill and the associated fugitive methane emissions, provided that:

a. (A) The organic material that is used as a feedstock would otherwise have been disposed of by landfilling, and the diversion is additional to any legal requirement for the diversion of organics from landfill disposal."

This raises questions regarding the implementation of SB 1383 and the use of sewage sludge biogas. Sludge is first digested, producing biogas, and then may be used in a variety of ways (land application, compost production, or landfill use as alternative daily cover). We assume all sludge being digested is considered to be voluntarily diverted from landfilling for the purposes of this section but please confirm. Similarly, the biogas may also be used in a variety of ways (electricity production, heating via boilers, pipeline injection, low carbon transportation fuel, etc.). We assume the choice to produce low carbon transportation fuel is taken voluntarily to comply with this section, but please confirm. (CASA2_FF31-3)

Agency Response: Section 95488.9(f)(2) applies solely to organic waste and dairy/swine projects and is not relevant to the wastewater sludge pathway. For the case of biogas production from raw sewage sludge, the end fate of sludge is not impacted by SB 1383 or the organic waste diversion goal since it is not typically landfilled or used elsewhere without first undergoing anaerobic digestion. End fate of sludge after digestion is irrelevant to the LCFS program since it is outside the system boundary considered in the life cycle analysis of wastewater sludge to biomethane. The choice for final disposition of biomethane (i.e., electricity production, low carbon transportation fuel) rests with the producer and is not mandated by the LCFS regulation.

J-8.2. Comment: The simplified calculator included in the appendices for wastewater sludge contains multiple assumptions which we question. For instance, the calculator assumes a 1% slip (loss) of methane from an anaerobic digestion system. What is the justification for such an assumption since that assumes a worse-case scenario and would not be seen in typical applications. The calculator also assumes the transportation fuel is imported from Texas and travels 800 miles with losses along the way. This is clearly not the case for California wastewater treatment plants. We are still working through other nuances of the calculators but have grave concerns since the CI's appear to be far higher than the established pathways currently in regulation. This is in contradiction to the opinions staff articulated when introducing the concept of the calculator when it was argued that conservative assumptions were utilized in developing the pathways. When using the calculator for specific projects it was expected that lower

CI's would result. We request additional time to evaluate the assumptions built in to the calculator, or modifications to it which better reflect real world experience using California wastewater treatment plants. (CASA2_FF31-4)

Agency Response: The Simplified CI Calculator for biomethane from wastewater sludge uses factors, where appropriate, from other biomethane Calculators to ensure consistency across all fuel pathways. The 1 percent slip (loss) factor is used to estimate fugitive methane losses during upgrading of raw biogas to biomethane. This value was developed after extensive stakeholder interactions during the transition from CA-GREET1.8b to CA-GREET2.0. The current regulation seeks to preserve the same treatment across all biomethane pathways (where applicable).

Concerns related to the impact on carbon intensity from '800' miles of biomethane transport are irrelevant to pathway applicants. This is because the CI for each biomethane pathway is calculated using a pathway specific pipeline transport distance.

It is likely the commenter is concerned about potentially higher CIs using the Calculator compared to Lookup Table CIs using CA-GREET2.0. This concern is unfounded since Lookup Table CIs were developed using conservative input values for representative biomethane pathways from wastewater sludge biogas. It requires applicants to conform to the stated process parameters and CIs for individual pathways to match or be lower than the Lookup Table CIs. It also required applicant familiarity with CA-GREET2.0. The proposed Simplified CI Calculator uses a streamlined approach with clearly labeled input fields and does not require expertise in CA-GREET3.0. CIs for individual pathways will match the actual operational parameters for each individual facility.

The Simplified CI Calculator for Biomethane from Anaerobic Digestion of Wastewater Sludge and the accompanying Instruction Manual were posted as part of the 45-day rulemaking package. Staff believes that the stakeholder engagement process for current rule making provided adequate time to review materials and submit comments regarding assumptions and life cycle methodologies used in the Simplified CI Calculator for this pathway.

J-8.3. Comment: Tier 1 Simplified CI Calculator for Biomethane from AD of Wastewater Sludge.

It is assumed that the "Commingling of Products" based on ARB's 2011 FAQ response will be what is allowed when other feedstocks are mixed (i.e Wastewater Sludge & Food Waste or Other Organic wastes).

<u>Recommended Action:</u>

1. Provide greater clarity in the regulations on commingling and mixing feedstocks, and thus the required reporting and monitoring requirements. Also provide clarity

on if every single feedstock will require a CI score (some WWTPs received 30-40 different organic waste feedstocks). (BLUESOURCE1_FF70-10)

Agency Response: Please see Response J-8.5 in Chapter VI.

J-9. *Fuel Pathway Classifications and Application Process*

J-9.1. *Margin of Safety*

Comment: REG requests clarification for the conservative margin of safety concept. Upon first glance, it appeared to be the max CI number to be used in the case of over generation. For example, if a plant had a 36 CI and a conservative CI of 38 for an average of 37, it would need to stay under the 38 CI. However, upon continued review, it looks like the average CI is the max CI. Going back to our example, the plant would have to stay under the 37 CI instead of the 38 CI. (REG3_FF44-25)

Agency Response: Please see Response J-9.5a in Chapter IV.

J-9.2. Multiple Comments: *Provisional Pathway Applicability*

Comment: As currently written, the section for Provisional Pathways in 95488.9 can be interpreted as a hard limitation of applicability to only "facilities that have been in operation for less than 24 months". This interpretation does not allow an existing facility (with or without an established pathway CI) from securing a Provisional Pathway when demonstrating less than 24 months of operating data applicable to their circumstances, including continuous improvement efficiency projects as well as adding "new" technology or CI-reducing processes. This prevents the entity from securing the additional credits associated with the new lower CI for the 24-months it would take to collect data necessary for a non-provisional Tier 1 or Tier 2 application plus the additional time for validation and CARB review leading to certification. Those additional credits (and revenue) are needed to help the GHG reduction technology be cost-effective. Through multiple conversations with CARB staff, RPMG has been assured of the agencies intent to provide continued access to, and timely recognition of, essential incremental CI reductions. Waiting for 24+ months to collect operational data and apply for a conventional Tier 1 or Tier 2 pathway would be highly problematic and a very large disincentive to providers of all low-CI fuel types, including affiliated RPMG ethanol producers. Therefore, **RPMG highly recommends Section 94588.9(c) be amended to clarify as follows:**

(c) Provisional Pathways. As set forth in sections 95488.6(a) and 95488.7(a), LCFS fuel pathways are generally developed based on 24 months of operational data. The Executive Officer may consider Provisional pathway applications ~~from facilities~~ that ~~have been in~~ <u>demonstrate a period of</u> operation ~~for~~ less than 24 months, provided <u>that at least three months of</u> ~~they have been in~~ operation<u>al data is submitted</u> ~~for at least three months~~. Based on timely reports, the fuel

reporting entity may generate credits or deficits using a provisionally-certified CI. (RPMG3_FF41-2)

Comment: One area that has come up since the release of the 45-day package relates to Provisional Pathways (95488.9(c)). As currently written, Provisional Pathways are limited to "facilities that have been in operation for less than 24 months". This definition limits the ability of an existing facility with an established CI and pathway from securing a Provisional Pathway when adding additional technology, like solar steam. Such large capital-intensive projects require the ability to generate credits once placed in service. Waiting for 24 months of operational data to apply for a conventional Tier 1 or Tier 2 pathway would be prohibitive. GlassPoint fully understands that provisional credits would be issued over the first two years of operation. We have discussed this issue on several occasions with staff who recommended we provide suggested language. GlassPoint suggest Section 94588.9(c) be amended as follows:

c) *Provisional Pathways. As set forth in sections 95488.6(a) and 95488.7(a), LCFS fuel pathways are generally developed based on 24 months of operational data. The Executive Officer may consider Provisional pathway applications from <u>new or modified</u> facilities <u>that have been in operation as configured</u> for less than 24 months, provided they have been in operation for at least three months. Based on timely reports, the fuel reporting entity may generate credits or deficits using a provisionally-certified CI.* (GLASSPOINT2_FF54-4)

Agency Response: Staff agrees that the provisional pathway applicability is too limiting by excluding facilities that are in production for more than 24 months but have recently undergone modification or upgrades leading to higher production efficiencies. In response to stakeholder comments, staff revised regulatory text to permit such facilities to apply for provisional pathways.

J-9.3. *Tier 2 Application Process for Electricity Pathways*

Comment: Additionally, San Francisco remains concerned that there have been no significant changes to the Tier 2 Pathway application process to more clearly define how providers of zero or low-CI electric energy can document their lower CI.

…

<u>The Tier 2 Pathway application process for electric providers is not well-defined</u>

San Francisco remains concerned that there have been no significant changes to the Tier 2 Pathway application process for providers of zero or low-CI electric energy to document their lower CI. Instead, the application process continues to focus on providers of liquid fuels. In its initial comments, San Francisco had proposed specific methods (based on CARB's own CA GREET model and proposed "book and claim"

methodologies) that would facilitate the Tier 2 Pathway application process for electric energy providers.[10]

[10] See, Comments of the City and County of San Francisco on CARB's Proposed Revisions to California's Low Carbon Fuel Standards, and attachment (dated April 23, 2018).

(CCSF3_FF51-4)

Agency Response: Please refer to Response J-9.4 in Chapter IV.

J-10. *Temporary Fuel Pathways*

J-10.1. *Proposal for Assigning Dairy Biomethane Temporary CI*

Comment: b. Many California dairy digesters are being developed in "clusters" of multiple digesters supplying biogas to one common destination. Each time a new digester is brought online in a cluster, that digester will operate under the -150 temporary pathway for at least three months, even though currently approved dairy biomethane pathways show the likely CI score for this fuel is -200 or lower. Consequently, new digesters could lose valuable CI scores each time they expand the cluster with new digesters.

c. We propose that after a dairy digester cluster has at least three active digesters with provisional or certified pathways, the temporary pathway CI value of each future digesters added to the cluster be set to the weighted average of active CIs for that cluster. The Executive Officer already may have the power to approve these new temporary pathways under 95488.9(b)(4),but we suggest making that power explicit in the case of dairy digester clusters. (MEW1_FF40-8)

Agency Response: The recommendation is based on the assumption that a new digester that comes online in the cluster is likely to have a CI similar to previously certified CIs for other digesters in the same cluster. However, given the likelihood for variability in manure management practices and biogas upgrading technologies for the new digester, the CI of newly supplied biomethane from a new digester can be significantly different from previously certified CIs. Staff prefers applicants request the use of a temporary CI for each of the digester projects as they come online. The availability of a Tier 1 Simplified CI Calculator is expected to expedite review and certification of such pathways, limiting the period during which a temporary CI will be used to report biogas sales in the program.

J-10.2. *Temporary CI Value for other Renewable Fuels*

Comment: However, a similar temporary CI value must be applied to other renewable fuels, as set forth in the comments below, not just to CNG/LNG. (CRF2_FF42-5)

Agency Response: The proposed regulation established temporary CIs for numerous alternative/renewable fuels in addition to CNG/LNG.

J-10.3. Multiple Comments: *Temporary CI Value for Swine Manure Biomethane*

J-10.3a. Comment: We believe it would be prudent to include swine manure in §95488.9 Table 8. There are numerous hog feedlots that could capture methane gas from lagoons and repurpose it as biomethane. Providing them with a temporary pathway CI value will help reduce GHG emissions from agricultural operations and help achieve program goals of reducing average carbon intensity in transportation fuels by 20% by 2030.

…

Recommended Actions:

1. Add biomethane CNG, LNG and LCNG from swine manure using grid electricity, natural gas, and/or parasitic load to Table 8. (ECOENGINEERS2_FF21-3)

Comment: We believe it is a mistake to exclude swine manure from §95488.9 Table 8. There are numerous hog feedlots that could capture methane gas from lagoons and repurpose it as biomethane. Providing them with a temporary pathway CI value will help reduce GHG emissions from agricultural operations and help achieve program goals of reducing average carbon intensity in transportation fuels by 20% by 2030.

...

Recommended Actions:

1. Add biomethane CNG, LNG and LCNG from swine manure using grid electricity, natural gas, and/or parasitic load to Table 8. (BLUESOURCE1_FF70-2)

   Agency response: Unlike dairy operations, staff does not have real data to make a CI determination on RNG produced from hog feedlots operations. Staff may consider adding temporary pathway CIs for biomethane CNG, LNG and LCNG from swine manure in the future if data are available. However, the proposed regulation does not prevent applicants from applying for CIs for swine manure RNG pathways either using the Simplified CI Calculator or a Tier 2 pathway.

J-10.4. *Process for Entities to Create a New Temporary Pathway and CI*

Comment: Furthermore, biofuel production facilities with feedstock-fuel combinations not identified in Table 8 are currently forced to use the baseline CI value for CaRFG or ULSD. We believe there will be biofuel production facilities with feedstock-fuel combinations not identified in Table 8 who will want to apply for a unique temporary pathway CI value for their facility. Many of them may have operating data or design data to model a reliable score. Providing entities with a clear process to obtain a temporary CI value will result in greater efficiency in credit generation from new projects. It is not clear in the proposed regulations, whether this option is allowed or

what alternatives are available for gasoline or diesel substitute feedstock-fuel combinations not identified in Table 8.

…

Recommended Actions:

2. Provide a process for entities to create a new temporary pathway and CI to be added to Table 8. Also, provide a process for an entity to create a new temporary CI value for a temporary pathway that is currently listed in Table 8. (ECOENGINEERS2_FF21-4, BLUESOURCE1_FF70-3)

   Agency Response: Fuel producers or pathway applicants are permitted to request new temporary fuel pathway CIs for feedstock-fuel combinations not identified in Table 8. Complete details to apply for a new temporary pathway CI are provided in section 95488.9(b). Requests to update temporary CIs for feedstock-fuel combinations currently proposed in Table 8 will not be permitted. Please see also Response J-9.7a. in Chapter IV.

J-10.5. *Retaining Original Pathways and Carbon Intensities*

Comment: 1. It seems premature and unnecessary to eliminate previously adopted pathways and assign them higher carbon intensity (CI) values that appear arbitrary. We highly recommend retaining the original pathways and CI values until project specific values are developed. This is especially true for transportation fuel derived from wastewater biogas for which there is a proposed six-fold increase in the CI for large wastewater treatment plants. (CASA2_FF31-1)

Agency Response: A biomethane pathway from a large wastewater facility certified with a pathway CI of 43.02 g/MJ using CA-GREET2.0 utilized operational parameters of this facility. The Tier 1 Simplified CI Calculator developed using the CA-GREET3.0 model has been tested with the same inputs for this wastewater pathway and is similar to the CI certified using CA-GREET2.0. Staff, therefore, does not agree with the commenter that pathway CIs with the new model appear to be arbitrarily higher. A change from previously available Lookup Table pathway CIs for wastewater biomethane is due to a change in the life cycle approach of wastewater pathways to harmonize this pathway across a similar pathway (i.e., landfill biomethane). The change however, is not six-fold as stated by the commenter. Please see also Response J-10.1 in Chapter IV.

J-10.6. *Determining Temporary Carbon Intensities*

Comment: 1. Table 8 – Temporary Pathways for Fuels with Indeterminate CI. This table provides a temporary CI value of 50 g CO_2e/MJ for CNG derived from wastewater sludge biogas. This change is without explanation (that we can find) and unfounded, as well as unnecessary. It is more than a six-fold increase from the established pathway for large wastewater treatment plants and almost double the value for small plants. The

previous draft regulations had increased the CI to 40 g CO_2e/MJ and likewise appeared unfounded. According to the Initial Statement of Reasons (ISOR) for that draft, it appears it was calculated based on the previous pathway for small treatment plants of 30.5. The ISOR stated that it added 5% to this value and then rounded upward to the nearest multiple of 5 value (which should have computed to a value of 35 rather than 40). Then, as now, there is no justification offered for this increase. We strongly recommend the retention of the existing pathways as noted in our general comment above. (CASA2_FF31-2)

> **Agency Response:** To determine conservative temporary CIs, staff followed a method that takes the highest certified CI for a particular fuel pathway, adds 5 percent of the CI and rounds the CI to the nearest five. The highest certified CI for wastewater sludge digestion pathway is 43.02 gCO_2e/MJ. Hence, staff proposed a revised temporary CI value of 45.0 gCO_2e/MJ based on the above method.

J-11. *Co-Processing*

J-11.1. Comment: First, the current GREET 3.0 model does not support a framework for the evaluation of these pathways. Any effort to 'build out' GREET 3.0 to accommodate these pathways should be subject to public review, just as changes which affect renewable CI's have been. It is strong and positive public policy to engage the public before fundamentally changing the model. We encourage CARB to build a co-processing specific calculator which would ultimately be incorporated into a regulation. Much thought and discussion needs to be had about how to calculate incremental energy demand related to co-processing, what is considered an appropriate baseline, how to account for adjustments in crude slate, and product yields. These are fundamental questions which will have significant impacts on these pathways. CARB ought to have specific, clear rules on these questions. They are beyond the realm of a guidance document or protocol and should be included in the regulation, similar to carbon capture and sequestration or the refinery investment and credit pilot program.

We believe that without a separate, public process to develop a co-processing framework, refineries will submit heavily redacted life cycle report and life cycle models which will be so redacted as to yield public scrutiny impossible. REG has submitted several Tier 2 pathways, one of which received public comments. We welcomed these comments as sign that stakeholders care about the integrity of the program. (REG3_FF44-32)

> **Agency Response:** Staff understands the importance of engaging the public and stakeholders in developing a co-processing quantification framework that will be used in the CA-GREET3.0 model to estimate the quantity and carbon intensity scores of co-processed renewable fuels. Staff has already organized four co-processing workshops and will continue to engage the public and stakeholders though additional workshops in the future to develop and finalize guidance on quantification of such projects. The previous workshops focused on various pertinent questions raised by the commenter above such as incremental

energy demand emissions, baseline data, product yields, etc. The public engagement process has been transparent and the proposed regulation allows for the use of the modified GREET3.0 model that conforms with the CARB guidelines and templates in estimating the quantity and carbon intensity scores of co-processed renewable fuels. Hence, staff believes that a separate rulemaking is not necessary at this time. Staff is committed to ensuring that pertinent information and data are provided to the public during a 10-day comment period for co-processing fuel pathways to provide informed comments, as is required for all Tier 2 pathways.

J-11.2. Comment: REG is also concerned that CARB will be encouraged by co-processors to validate the production of renewable gallons using a mass balancing method. This is unacceptable, no matter the feedstock or process utilized. As REG, NBB, and the Joint Research Center (JRC) can demonstrate, ^{14}C radio carbon assay, whether conducted using method B or C of ASTM D6866 is extremely accurate and affordable. Any acceptance of mass balancing moves the LCFS further away from the premise that actual benefits be received by Californians in order to participate in the program (a basic tenant within AB32). An amount of co-processed fuel, resulting in a ton of carbon reduction, sent to Ohio, while beneficial to the residents of Ohio, does nothing for the residents of California. (REG3_FF44-33)

Agency Response: Staff is evaluating different methods for quantifying renewable volumes, including the ^{14}C method. After the renewable volume is quantified using an acceptable method, applicants can use a mass balance accounting method to claim credits for petroleum fuels used in California.

J-11.3. Comment: We understand CARB's desire to facilitate the near-term ability of obligated parties to generate LCFS credits. However, due to the immense scale of refining operations and their astonishing level of complexity, we believe more time is needed to study this subject before carbon intensity pathways are issued. (NBBCABA3_FF4-2)

Agency Response: Please see Response J-12.2 in Chapter IV.

J-11.4. Multiple Comments: ***Co-Processed Renewable Diesel***

Comment: Specifically, we recommend that CARB restart its Co-processing Workgroup to help ensure pathways are promulgated in a manner that is 100% accurate for each refinery project and carried out in a manner fully consistent with the long-term goals of the LCFS program. <u>We further believe that no pathways should be approved until the Co-processing Workgroup has reviewed key issues and developed a set of recommendations.</u>

We suggest the following areas for further consideration by CARB and/or the Co-processing Workgroup:

- Lifecycle models. CARB suggests that "Evaluating co-processing pathways using a Tier 2 framework is consistent with the goal of streamlining the pathway

application and certification process."[1] At this point in time, we disagree that this is an appropriate approach because models for each respective refinery technology do not exist—they still need to be developed by CARB. And since the Tier 2 framework is usually masked in redacted statements, that process alone will not afford the level of public review necessary to provide confidence to stakeholders that carbon intensity values are accurate.

1 https://www.arb.ca.gov/regact/2018/lcfs18/isor.pdf page III-72

- Public information. Refineries should be required to provide the same level of operational detail that has been made available by and for other industries. If co-processing is allowed to generate LCFS credits, the technology must go through a public process that provides sufficient information for the public to validate the accuracy of carbon intensity pathways. In addition, data marked as "confidential business information" submitted on Tier 2 applications should be reviewed by CARB legal staff to ensure it meets the criteria set forth under California law.

- Verification of renewable content. It is believed that a very small fraction of renewable feedstock inputs become renewable diesel fuel through co-processing. Therefore, it is critical that renewable content in finished fuel be measured via C14 radiocarbon dating rather than a mass-balance approach, which would overestimate renewable content. ASTM test method D6866 has been approved for this analysis.

- Limitation on co-processing. If co-processing is allowed under the LCFS, boundaries for this type of credit generation should be considered. We recommend the Refinery Investment Credit Pilot Program (RICPP) as a sensible model. Under RICPP, projects are of limited duration, refiners are not allowed to generate more than 20% of their obligation through the program, and credits cannot be traded. Given the incredible complexity and scope of refinery operations—and the corresponding potential for outsized errors—we believe moving forward in a methodical way is justified. (NBBCABA3_FF4-3)

Comment: Technical properties. Potential concerns about cold-flow performance, stability, and incomplete refining could require additional test parameters and limits to be included. (NBBCABA3_FF4-10)

Comment: Alternative Diesel Fuel (ADF) regulation. Co-processed renewable diesel is a new fuel that should go through the ADF process like biodiesel has—and other renewable diesel replacement fuels will in the future. This step would ensure that emissions, public health, and operability data is available to CARB and the public for evaluation. (NBBCABA3_FF4-12)

Agency Response: Please see the response to NBBCABA3-FF4-9 in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations. Please also see Response J-12.2 in Chapter IV.

J-11.5. Comment: Additional processing. Carbon intensity pathways should account for energy used when (and if) refineries isomerize co-processed fuels to improve cold flow performance. (NBBCABA3_FF4-8)

> **Agency Response:** Consistent with other fuel pathways, carbon intensity scores would be based on well-to-wheel LCA analysis that include all energy use along the supply chains, including isomerization if it occurs.

J-11.6. Comment: We understand CARB's desire to continue with designing a framework for co-processing, we recognize that co-processing is important to CARB's fuel neutral approach. However, we believe that a new, separate rulemaking should take place before any new pathways are approved. While it has been CARB's position that co-processing is a Tier 2 application, we must disagree for several reasons. (REG3_FF44-31)

> **Agency Response:** For all practical purposes, a co-processed fuel is the same as any other alternative fuel and can be covered under the Tier 2 application framework. There is no need to initiate a separate rulemaking for co-processing. To ensure that transparent and robust methods are developed and used in quantifying renewable volumes and CI scores, staff has conducted a series of co-processing workshops in the past and is planning to hold additional workshops in the future. Please see also Responses J-11.1 and J-11.3 in this chapter.

J-12. *Indirect Land Use Change*

J-12.1. *Calculation of Direct and Indirect Emissions of Corn and Cane Ethanol*

Comment: Growth Energy has several concerns regarding the Proposed Modifications, and believes several changes could be made to enhance the regulation. For example, to ensure the Proposed Amendments are based on "the best available economic and scientific information" available to CARB, (Health & Saf. Code, § 38562, subd. (e)), Growth Energy recommends that CARB modify its calculation of the direct and indirect emissions of corn and cane ethanol, and use updated versions of CA GREET and GTAP. (GROWTHENERGY2_FF56-1)

> **Agency Response:** Where appropriate, staff has modified the direct emissions of corn and cane ethanol pathways in response to stakeholder comments, including those of Growth Energy. This includes updating the CA-GREET2.0 to CA-GREET3.0 to reflect changes in crop production, transport, fuel production and final use of ethanol from both corn and cane feedstocks. With regard to revising GTAP values for indirect emissions, please see Response J-14.2 in Chapter IV.

J-12.2. *Carbon Intensity Values for Corn Ethanol, Cane Ethanol, and Electricity*

Comment: I. The CI Values for Corn Ethanol, Cane Ethanol, and Electricity should be <u>Based on the Best Available Economic and Scientific Information</u>

AB 32 requires that, in adopting amendments to the LCFS regulation, CARB establish "the maximum technologically feasible and cost-effective" method of reducing greenhouse gas emissions. (Health & Saf. Code, § 38561, subd. (a).) CARB must also use "the best available economic and scientific information . . . ." (Health & Saf. Code, § 38562, subd. (e).)

As an initial matter, Growth Energy asks that CARB define what it contends the term "best available scientific information" means. This is important so that a reviewing court can assess whether CARB is reasonably construing the term for purposes of its development of the Proposed Amendments. This is of particular concern here because CARB appears to be relying on little scientific information in its efforts to provide credits for unused infrastructure, while at the same time declining to give adequate consideration to new data and findings concerning the direct emissions of various fuels and indirect land use change impacts. (GROWTHENERGY2_FF56-12)

> **Agency Response:** The proposed amendments are based on the best available data and information. Staff has evaluated the pertinent information and data and has reviewed relevant literature to the extent possible to inform the proposed regulation and provide responses to stakeholder comments. CARB has communicated openly with stakeholders to inform the proposed design of the infrastructure crediting provisions, including two public workshops on June 20, 2018 and August 8, 2018, which highlighted this topic.
>
> With regard to direct emissions of various fuels, staff has updated values where appropriate in light of new and best available information including all updates from the Argonne GREET1_2016 model and other available data (i.e., sorghum agricultural data, intensity and fuel economy for MDHD and HHDD trucks). In response to indirect land use change, please see Responses J-14.1 and J-14.2 in Chapter IV.

J-12.3. *Indirect Land Use Value for Corn Starch Ethanol*

Comment: Using CARB's AEZ-EF model in conjunction with GTAP to estimate emissions associated with the various land use changes, researchers have determined that the ILUC for corn starch ethanol should be reduced from 19.8 g/MJ to 10.3 g/MJ. (GROWTHENERGY2_FF56-39)

Comment: The current ILUC for corn starch ethanol is based on 2011 conditions, which correspond to a drought year in the U.S. that negatively impacted corn yields. When a three-year average is used, the ILUC should be reduced significantly. (GROWTHENERGY2_FF56-40)

Comment: Growth Energy also notes the Proposed Modifications do not include many of the revisions requested in its April 27, 2018, comments relating to indirect land use emissions. Such revisions are particularly important with respect to CARB's continued use of an outdated GTAP model. Specifically, researchers at Purdue University updated the GTAP model in 2017, and those updates were reported in the peer review

literature in July 2017. That model has been available to the public and CARB for an entire year, and includes many updates that correct known errors and inaccuracies in the prior model. (See Exhibit "A" at 1.) By failing to update its indirect land use change values to reflect the current version of the GTAP, the Proposed Amendments are not based on the "best available scientific information," (Health & Saf. Code, § 38562, subd. (e)), and also fail to achieve the "maximum technologically feasible and cost-effective reductions in greenhouse gas emissions." (See Health & Saf. Code, § 38560.5, subd. (c).) (GROWTHENERGY2_FF56-17)

Comment: The 15-day notice fails to address our 45-day comments on the need to update indirect land use emissions in these current LCFS amendments, and the significant impacts of doing so.

ARB uses the Purdue University GTAP model to evaluate indirect land use emissions. Our comments point out that the current GTAP model which addresses many issues with indirect land use emissions raised over the last few years was developed by Purdue, and reported in the peer reviewed literature in July 2017. The literature indicates that the indirect land use change emissions for corn would have dropped from ARB's current estimate of 19.8 g/MJ to around 10 g/MJ. This model has been available from Purdue for use by ARB since July 2017 (the model is available to the public), and using ARB's previous 30 sensitivity cases for the various input elasticities, it could have generated new indirect land use estimates for all biofuel feedstocks in a few weeks, certainly by September of 2017. The regulatory calendar for the LCFS regulation allowed ample time to use the new, correct GTAP values. Because the Proposed Amendments do not use indirect land use change values from the current GTAP model, the Proposed Amendments are not based on the best available scientific information. (GROWTHENERGY2_FF56-58)

Agency Response: Please see Responses J-14.1 and J-14.2 in Chapter IV.

K. Crude Oil and Innovative Crude Production Method Provisions

K-1. Multiple Comments: *Support for Proposed Modifications to the Innovative Crude Production Provisions*

Comment: WSPA does appreciate that the 15-day Modifications include credits for transporting crudes using innovative methods. (WSPA5_FF19-17)

Comment: Kore Supports Further Expansion of Innovative Crude Provision

According to the Summary of Proposed Modifications, the intent of §95489 is as follows:

> *"In section 95489(c)(1)(A), additional technologies are proposed to be recognized as eligible to generate credits under the innovative crude provision. Geothermal, ocean wave, ocean thermal, and tidal current energy are proposed to be recognized as innovative methods. Uses of biomethane and biogas are also proposed to be recognized. For each method, proposed modifications clarify that energy must be physically supplied to the crude oil production facilities. Staff believes that each of these additional technologies are in keeping with the intent of the provision to promote the use of innovative technologies to reduce emissions during crude oil production."*[1]
>
> [1] See Notice of Public Availability of Modified Text and Availability of Additional Documents and Information dated April 20, 2018, Summary of Proposed Modifications at p. 19, available at https://www.arb.ca.gov/regact/2018/lcfs18/15daynotice.pdf

Kore supports the expansion of the innovative crude provision to enable additional technologies to reduce emissions during crude oil production. (KORE1_FF23-1)

Comment: We support CARB's continuing efforts to improve the LCFS program in general, and the Innovative Crude and lower CI pathway provisions specifically. (GLASSPOINT2_FF54-1)

Comment: We appreciate CARB's recognition of the potential for solar steam to deliver meaningful emissions reductions in the production of liquid fuels, through both the Innovative Crude provisions and the recognition of low-carbon energy sources for biofuel refining. We believe these provisions are appropriate given the program's fundamental focus on fuel life cycle emissions and will help provide a price signal which will create projects that deliver economic growth while reducing both criteria pollutants and GHG emissions. (GLASSPOINT2_FF54-2)

Comment: GlassPoint previously submitted detailed comments on the original 45-day proposal[1]. We would like to specifically support the following proposed revisions in this package:

[1] https://www.arb.ca.gov/lists/com-attach/77-lcfs18-Wj1cNgFhU3MEcVQk.pdf

- The additional bin for 45% steam quality, and the correction to the 95% quality bin;

- The additional eligibility for innovative methods associated with crude oil transportation;
- Simplified reporting for crude delivered to in-state refineries. (GLASSPOINT2_FF54-3)

Comment: RNG Coalition supports the provisions allowing credit generation for crude oil that has been produced or transported using innovative methods and delivered to California refineries for processing. (RNGC3_FF46-8)

> **Agency Response:** Staff appreciates the support for the proposed modifications to the innovative crude provision.

K-2. *Crude Oil Provisions*

K-2.1. *Oil Production Greenhouse gas Emissions Estimator Model*

Comment: The changes in § 95489(b)(3)(C) presented in the 15-day Modifications reflect direct input from the Oil Production Greenhouse Gas Estimator (OPGEE). A key element to the accuracy of OPGEE is the availability of field data to support the complex model algorithms. Based on the fact the concerns about data unavailability have previously been raised, we are surprised that an update to this intricate tool with a wide number of parameters was completed before validating the inputs to the model. Further, the model contains structural defects in the use of unverified default values that make the model inaccurate when compared to verified GHG inventories. Finally, the model does not take into account reductions due to California's Cap & Trade program, Federal and State regulations, or third-party verified voluntary emission reduction initiatives. The paragraphs below detail these concerns and propose changes to further the integrity of the LCFS program.

Data on Field Characteristics

WSPA continues to express concern regarding the apparent lack of detailed data with which to populate the tool for a vast number of fields outside North America. Without such data, use of the tool is without factual basis and may tend to underestimate carbon intensities for fields that exceed default values for flaring and venting among other emission scenarios.

While there are hundreds of crude types and associated CIs listed in the LCFS at Table 9, 26 made up 90 percent of the crude refined in California in 2015-17. In reviewing the 11 non-North American origin crudes in that 90th percentile group, of the 60 plus variables that the model will accommodate, an average of 14 variables are specific to the field and are used to estimate CI. Several of those variables are estimates or assumptions.[1] However, in reviewing the 15 North American crudes (Alaska plus 14 California crudes) that make of the rest of the 90th volume percentile, an average of 30 variables are specific to the field. Where data is unavailable, default values are used in the model leading to inaccuracies. The large uncertainty introduced

with the use of default values again brings into question the practical usefulness and validity of the OPGEE tool in a regulatory setting.

[1] Of the missing data for all non-North American entries include gas-to-oil ratio, water-to-oil-ratio, fraction of electricity generated onsite, associated gas processing technology, flaring-to-oil ratio, venting-to-oil ratio, among the many.

(WSPA5_FF19-12)

Agency Response: Staff has been very transparent about the limitations of the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) model and the data sources used to estimate CI values for individual crudes (e.g., see comment "LCFS 37-3" and CARB's response in the Final Statement of Reasons for the 2015 re-adoption of the LCFS and comments "CIPA1 and CIPA2" from the Final Statement of Reasons for the 2011 LCFS amendments). As stated in past CARB responses, while very good data is available for California, Alaska, western U.S., Alberta oil sands, and some foreign crudes, CARB staff agrees that the lack of accurate data on production parameters for many imported crudes is a problem. This lack of data takes two forms: lack of field production data and lack of data that maps field production to marketable crude blends. CARB staff has explored options for obtaining this data from several data collection sources and have asked refiners and oil producers to supply this data with very little success. Oil producers are also encouraged to supply data to CARB in order to help maintain a robust database. If crude-specific data cannot be obtained and are not provided by producers, the OPGEE assigns default parameters when estimating the carbon intensity for these crudes. OPGEE defaults are based on available information for a parameter and within the range observed worldwide. Detailed documentation of the OPGEE model and the default values used in the model have been provided to stakeholders for review with every update to the model. Moreover, for some input parameters, OPGEE makes use of "smart defaults." Smart defaults are used by OPGEE for those parameters that can be correlated to other parameters that are often known. For instance, the produced water-to-oil ratio is often unknown, but this parameter can be correlated to field age which is almost always known. CARB staff believes that these default parameters generally result in conservatively high CI estimates for crudes that are lacking in quality data. Producers who do not believe that these defaults accurately represent their crude production are encouraged to provide CARB with complete and accurate data. CARB staff has engaged with stakeholders on the OPGEE model and inputs used to estimate CI values for individual crudes using the model for seven years. This engagement has included several workshops before which updated versions of the model, model documentation, and crude parameter inputs were posted publically. At all of these public engagements, staff has expressed the willingness to work with stakeholders to improve the model calculations, default values used in the model, and input values used for modeling individual crudes. In those few cases where stakeholders have come forward with data to improve the model and the model inputs, both CARB staff and Adam Brandt (lead author of the model at Stanford University) have been willing to engage and make corrections where appropriate. CARB staff notes that many of the oil companies represented by the commenter

produce a significant amount of the crude oil worldwide and may thus have access to much of the data that the commenter claims is lacking. Staff would welcome access to this data and highly encourages the oil industry to transparently provide the data for use by CARB and other organizations worldwide.

K-2.2. *Crude Lookup Table*

Comment: In addition to the question about liquefied hydrogen as outlined above, our review of the CARBOB and ULSD pathways in Attachment C of the 15-Day Modifications indicates a potential error in the 2010 crude CI from the revised OPGEE model. As noted in Table 1 of Attachment E ("Estimating Carbon Intensity Values for the Crude Lookup Table") of the 15-Day Modifications, the 2010 baseline crude average CI is 11.75 gCO2e/MJ, while Attachment C states that the 2010 crude CI is 11.78 gCO2e/MJ.

This results in a slight overestimate (~0.03 gCO2e/MJ) for the CARBOB and ULSD pathways as presented in Table 7-1 of the modified regulatory text. Revising these estimates would also necessitate revising the benchmarks in Tables 1, 2, and 3 of the revised regulatory text. In addition, the California crude average applicable to 2018 and subsequent years in Table 9 needs to be updated to reflect the correct value as well as the baseline crude average equations in Section 95489(a). (WSPA5_FF19-8)

> **Agency Response:** Staff posted the wrong version of Attachment E to the first 15-day notice. The corrected version was included in the second 15-day notice. The 2010 crude CI baseline is 11.78 gCO_2e/MJ.

K-2.3. Multiple Comments: *Calculating Crude CI with GHG Inventory Data*

Comment: While we are aware that component counts for some fugitive sources were based on 2007 California-specific survey data, the emission factors are very outdated and do not reflect current monitoring activities for state and federal programs. As with most industries, much has changed in the California oil fields in the past 25 years. California producers have been at the forefront of voluntary and regulatory emission control over the past two decades including implementation of leak detection and repair programs (LDAR) and replacement of pneumatic devices with low or no-emitting devices that make these emission factors, including component counts obsolete if not outright incorrect. Further with the implementation of federal rules (e.g., NSPS OOOO/OOOOa) and state rules (e.g., ARB's Oil and Gas Methane Regulation), many other sources (such as tanks and well completions) in the U.S. and especially in California have been significantly reduced or eliminated.

Many California producers are also required to exhaustively inventory and report GHG emissions under State and Federal laws. Equipment is counted and cataloged, fuel is measured, meters are calibrated and emissions are calculated based on science-based protocols. Emissions and production data reported under the California program are further third-party verified for covered emissions and petroleum products. However, the

results of these inventoried emissions and verified production do not correlate well with CIs generated by OPGEE for California fields.

This lack of convergence is especially troubling given the much greater reliability and availability of data on crude production in California compared with the hundreds of crudes produced outside California and lack of reliable data for foreign crudes as detailed in the paragraphs above. WSPA proposes that for fields in California, ARB add an option to LCFS that allows, at the discretion of the operator, a calculation of a field CI using verified emissions and production data. (WSPA5_FF19-14)

Comment: A key element to the accuracy of the Oil Production Greenhouse Gas Estimator (OPGEE2.0) tool is the availability of field data to support the complex model algorithms. Comparing California and Out-of-State crudes, there continues to be a large disparity in the numbers of field data and default inputs into the OPGEE model. A quick review of the Marketable Crude Oil Name (MCON) data file shows at least twice as many data inputs for California crudes as compared with non-California crudes. The ready availability of reported field data puts California crudes at a disadvantage in calculating carbon intensities as the default values substituted in the model for non-California crudes may tend to underestimate CIs due to the lack of the types of environmental controls required of California operators, such as tank and process vapor recovery, leak detection and repair programs, and installation of low-emitting or non-methane pneumatic control devices.

Further to this issue, we note that a great many California operators report greenhouse gas emissions from their oil production operations at both the federal and state level. Importantly, many of the state-level reporting is also third-party verified. However, when these greenhouse gas reports are combined with field production values (which are also reported and third-party verified) to generate field CIs, these values differ greatly from CIs modeled by OPGEE. As the data sources from production accounting and greenhouse gas inventory are from actual counts, sampling and analysis, and calibrated flow meters, this level of inventory is of a much higher validity. The lack of agreement with the OPGEE model calls into question the use of the OPGEE model in a regulatory setting such as the LCFS.

CIPA therefore suggests that CARB allow California operators to use verified emissions and production to calculate field-specific crude CIs for use in the LCFS at the discretion of the operator. CIPA proposes that CARB revisit the OPGEE model and incorporate MRR and other California data sources in future revisions to the model. (CIPA2_FF43-3)

> **Agency Response:** With regard to the commenters' claims that California oil fields likely have lower fugitive and venting emissions from equipment, staff agrees and has replaced OPGEE default values with lower emission factors for equipment such as dehydrators, storage tanks, and pneumatic devises in the modeling of California oil production. As stated in the comment, these lower emission factors were based on data from a 2007 survey of California oil fields.

Staff welcomes the opportunity to work with oil field operators in California to update these emission factors using more recent data.

Staff notes that both commenters claim that the results from the OPGEE modeling do not correlate well with CI values based on reported GHG emissions and production data. However, to date the commenters have provided no such calculations to support this claim. As stated in responses to similar comments provided in the 2015 LCFS Re-adoption, CARB staff agrees that "ground truthing" is an important test of the validity of the model approach that should be undertaken. Unfortunately, staff has yet to find an oil producer willing to supply the necessary data to ground truth or calibrate the model against actual GHG emissions. Since the commenters represent producers of a vast majority of the oil in California, staff would welcome their participation in such an endeavor.

Furthermore, staff disagrees with the recommendation of relying exclusively on reported GHG inventory emissions together with production data to calculate the CI of crude oils, because this approach does not account for the life cycle GHG emissions associated with producing and transporting the crude oils. GHG inventory emissions do not include emissions from land use change, transport, or upstream production of process fuels such as natural gas and electricity. As always, staff is open to revise the CI values of individual California oil fields if all operators within an oil field can provide operational data, including all process fuel use, venting and fugitive emissions from the field, and production data.

K-2.4. *OPGEE Model Defaults*

Comment: The note below Table 35 indicates: "Note that the OPGEE model defaults to most equipment used in CA crude recovery being powered by natural gas, due to the lack of real-world data. The fuel shares of the CA crude recovery are weighted averages of the top 16 crude sources, which represent 76.6% of the total crude volume in CA." WSPA requests that ARB provide the rationale why only 16 crudes or 76.6% of crude volume are used instead of using all the crudes supplied to California since all the crudes are available in OPGEE. (WSPA5_FF19-23)

Agency Response: OPGEE model defaults to most equipment being powered by NG, because the crude recovery fuel use at field level is not available. NG is the dominant fuel source of California crude recovery. California refineries import crudes from approximately 200 oil fields in 2010, estimating fuel shares of crude recovery at each oil field in the OPGEE model would be challenging and staff believes that fuel shares numbers derived from the top 16 oil fields are representative of the California crudes with the current OPGEE default assumption. However, Staff welcomes stakeholder's inputs with respect to fuel shares in their oil field operation.

K-3. *Innovative Crude Production Methods*

K-3.1. *Book-and-Claim Accounting for Solar and Wind Electricity*

Comment: Similarly, the proposed regulatory language requires solar electricity be supplied directly to oil and gas fields and not through indirect accounting. This language is too limiting as implementation requirements for solar such as flat, level ground for ease of maintenance and optimal performance do not coincide with all oil production which often occurs in hilly areas. (WSPA5_FF19-16)

> **Agency Response:** Please see Response in K-3.6 in Chapter IV on Book-and-Claim Accounting for Solar and Wind Electricity.

K-3.2. *Book-and-Claim Accounting for Renewable Natural Gas*

Comment: In 95489(c)(l)(A)(6), CARB has provided amended language allowing RNG or biogas energy used for the production or transport of crude oil to generate LCFS credits. DTEBE thanks CARB for explicitly allowing the use of RNG in this fashion. However, the requirement that RNG be physically supplied to the crude oil production facility may be unrealistic and is unlikely to generate credits in the LCFS program. RNG is delivered throughout the industry using Book-and-Claim accounting, which is explicitly allowed when using RNG as a vehicle fuel in the LCFS program. <u>DTEBE asks that CARB amend these provisions to allow RNG delivered to crude oil production sites using Book-and-Claim methods be allowed to generate LCFS credits.</u> Allowing for indirect delivery still results in carbon emission reductions and results in additional carbon reduction for these projects, as it provides a new offtake opportunity for RNG outside of vehicle fuel. Using RNG for this purpose will undoubtedly spur new project development, especially for RNG processed from higher CI feedstock such as organic waste. This is an exciting potential pathway for RNG, and providing amended language that allows for RNG delivery will help bolster the use of RNG in the LCFS program and the development of new RNG projects in California. (DTEBE2_FF20-8)

Comment: Pursuant to § 95489(c), Credits for Producing and Transporting Crudes using Innovative Methods – General Requirements (A.6), ARB has elected to not permit book and claim for RNG usage under this section. Yet it allows book and claim for both transportation fuel end use and renewable hydrogen production at refineries. The differentiator of RNG as a fuel versus raw material to produce transportation fuel provides no greater or lesser reductions. Book and claim is an essential enabler for matching RNG supply with demand because the projects are frequently located in different geographical areas.

The restriction of direct supply also adds unnecessary and redundant pipelines to the project along with associated costs and encroachments, which will further hinder RNG use as an innovative crude production method. Finally, WSPA anticipates that allowing book and claim for these provisions could be a market driver for RNG projects across the entire country, providing the co-benefits of California's SB 1383 to a larger population and demonstrating California's global leadership in methane emission reduction.

…

In summary, WSPA views the requirement for direct physical supply of RNG and solar energy to crude oil production facilities as a missed opportunity to provide an appropriate incentive to develop this area of the program. We encourage ARB to re-evaluate their position and allow book and claim for RNG and solar energy under the LCFS. (WSPA5_FF19-15)

Comment: However, we are unsure what is meant by the requirement for Renewable natural gas (RNG) or biogas energy to be "physically supplied directly" to the crude oil production facilities. RNG is generated from feedstock at existing stationary sources such as landfills, wastewater treatment facilities and dairies and often cannot feasibly be located near a crude oil production facility.

For this reason, we ask that you consider alternative requirements that would enable pipeline-injected RNG sourced from within California to qualify under this provision. The California Public Utilities Code section 399.12 outlines a widely-accepted framework for the inclusion of pipeline-injected biomethane in the Renewable Portfolio Standard Program that we suggest using as a starting point. **We also ask that if the term "physically supplied" remains in the regulation, that you specify what methods are acceptable.** For example, if trucking or a dedicated pipeline are required to meet the standard, please list those potential options in the regulation. (RNGC3_FF46-9)

Comment: Consider alternative requirements for the transportation of renewable natural gas (RNG) to crude oil production facilities

The proposed modification that would allow for the generation of credit from producing or transporting crude oil to refineries within certain innovative methods, is itself an appropriate provision to incentivize using new technology and methods for procurement. But the requirement of RNG and biogas energy to be 'physically supplied directly" to crude oil facilities is one that is not practical. The procurement and transportation of RNG from existing stationary sources and infrastructure may not be located near a crude oil production facility and make it difficult to meet the requirement that was proposed by the Board`s staff. Therefore, it is necessary for the Board to consider alternative criteria for RNG or biogas energy that is supplied to crude oil production facilities. A more viable alternative would be to enable pipe-line injected RNG sourced within California to qualify. This would make it possible for RNG and biogas entities to take part without any additional burdens to participating and putting them on equal footing with other types of fuel. (CNGVC3_FF59-2)

> **Agency Response:** Staff disagrees with the recommendation to allow book-and-claim accounting for demonstrating the use of RNG under the innovative crude provision. Under staff's proposal, book-and-claim accounting can only be used for allocating RNG as transportation fuel or feedstock for producing transportation fuels such as renewable H_2. Book-and-claim accounting would not be allowed for RNG when used as process fuel at alternative fuel facilities, refineries or crude oil fields. Moreover, staff believes that the phrase "physically supplied" is

sufficient and does not need further elaboration as to all of the potential means to physically supply RNG to the oil field.

K-3.3. *Book-and-Claim Accounting for Electricity and RNG*

Comment: CIPA appreciates the expansion of renewable energy sources to the Innovative Crude Provisions. However, requirements that renewable natural gas (RNG) and solar electricity be provided directly to field operations significantly reduces the application of these techniques without any real benefit to reducing greenhouse gases.

For example, several of CIPA's member companies are investigating the use of RNG in their operations as a substitute for natural gas that is produced and transported from out of state, because of the lack of sufficient in-state quantities. Like non-renewable natural gas, the sources of RNG are not frequently located adjacent to the uses of RNG and siting them adjacent is not a development consideration. Thus, application of this provision will be limited to chance occurrences. It should be noted that an additional benefit of allowing book-and-claim of RNG would be to incent control of methane emissions from sources such as dairy and swine operations from sources that would not be subject to California's SB 1383, expanding California's leadership in reducing global methane emissions.

Similarly, CIPA's member companies have been evaluating installations of photovoltaic solar projects in and adjacent to oil fields in California. However, the constraint that the power be direct supplied to oilfield operations reduces application of PV solar to flat undeveloped areas near existing electrical infrastructure, which many oil fields cannot access without running new transmission lines over several miles. This additional expense is enough to make projects uneconomic. During this rulemaking, CARB extended Book-and-Claim opportunities for EV charging. This accounting methodology should be allowed for Innovative Crude provisions as well.

CIPA therefore requests that the requirements for direct sourcing of RNG and electricity from solar be removed so that greater use of these provisions can be made. (CIPA2_FF43-2)

> **Agency Response:** Please see the Response in K-3.6 in Chapter IV on Book-and-Claim Accounting for Solar and Wind Electricity and Response K-3.2 in this chapter on Book-and-Claim Accounting for RNG.

K-3.4. *Crude Oil Production and Transport Facilities*

Comment: Section 95489 (c)(1)(A)(1). To be internally consistent, each location that states crude oil production facilities should read "crude oil production or transport facilities" as it does for electricity in (3). (GLASSPOINT2_FF54-7)

> **Agency Response:** In response to this comment, staff has proposed to add crude oil transporter and crude oil transport facilities in the innovative crude provision text where appropriate in order to maintain internal consistency.

K-3.5. ***New Technology to be Considered as an Innovative Method***

Comment: Kore will begin a commercial scale demonstration of its technology beginning Q4 2018. The pyrolysis facility is located at a Southern California Gas site. The facility will convert about 1 ton/ per hour of various biomass feedstocks into pyrogas and biochar. The pyrogas will be tested for its efficacy as a replacement fuel for natural gas to produce steam used in oil extraction. This application could qualify as an innovative crude production method. The biochar will be tested for its feasibility as a soil amendment and/or fuel. The testing facility is being supported by SoCalGas and the South Coast Air Quality Management District ("SCAQMD"). The facility has received its air permits from SCAQMD.

…

Regarding the inclusion of biomethane and biogas as qualifying technologies, this expansion is likely based on ARB's recognition that oil refineries have flexibility in their industrial operations to use a range of energy sources, including fuels that have undergone lesser refinement. While fuels such as biogas are not approved for shipping on the natural gas pipeline or for use in CNG vehicles, a refinery that is properly configured can utilize biogas as an energy source for steam generation, maintain or improve its criteria pollutant emissions, and significantly reduce its GHG emissions.

This same reasoning and approach supports the inclusion of biomass-derived fuels that do not meet the current definition of biogas or biomethane that are contained in the Proposed Regulations. A core principle of the LCFS is technology neutrality, and the regulation has been highly successful in applying a performance-based approach to reducing the CI of transportation fuels. Consistent with this approach, it is recommended that ARB revise the language of proposed *§95489(c)(1)(A)(6)* as follows:

(1) *General Requirements.*

(A) For the purpose of this section, an innovative method means crude production or transport using one or more of the following technologies:

(…)

6. Renewable natural gas (RNG)<u>,</u> ~~or~~ biogas, ~~energy~~ <u>or other biomass-derived fuels</u>. RNG<u>,</u> ~~or~~ biogas<u>, or other biomass-derived fuels</u> must be physically supplied directly to the crude oil production facilities.

Such an approach would further achieve ARB's goal of enabling a wider range of innovative technologies to reduce GHG emissions in the transportation sector. (KORE1_FF23-2)

Agency Response: Staff has not researched the potential production and use of pyrogas derived from biomass resources as an energy source for crude oil production and its potential environmental impacts. At this late stage of the rulemaking process, there is insufficient time to properly evaluate the environmental impacts of the proposed innovative method. Staff looks forward to learn more

details about this fuel pathway from the stakeholder before considering it as an eligible innovative crude technology.

L. Refinery-Related Provisions

L-1. *Support for Proposed Modifications to the Refinery Investment Credit Program*

Comment: Shell specifically would like to express our support for two elements of this program, which cover both the manufacture of liquid fuels for transportation that California requires today and in the foreseeable future; ...

The products that Shell has safely and reliably made at our Martinez refinery for over 100 years will be needed in California for many more by the vast majority of its citizens. Continuing to make these fuels in California is the right approach for both the State's economy and reliability of its fuel supply. The Refinery Investment Credit Program (RICP) under LCFS, as amended in this rulemaking package, enables investments to reduce the carbon intensity (CI) of the fuels that Shell produces in California today. The changes that have been proposed by the ARB are pragmatic and will make the RICP workable. We look forward to considering ways for such changes to unlock project opportunities at our Martinez refinery once implemented. Every additional project the proposed changes may ultimately incent, at Shell's refinery and others in the State, will create new jobs and accelerate GHG emission reductions as well. Many of these projects also will offer criteria pollutant co-benefits. Any such outcome clearly would be a "win-win-win." (SHELL2_FF57-1)

> **Agency Response:** Staff appreciates the support for the Refinery Investment Credit Program (RICP).

L-2. *Refinery Investment Credit Program*

L-2.1. *Removing "Pilot" from the Title of the Program*

Comment: ARB staff has indicated an intention to remove the word "Pilot" from the title of this program. That edit to the regulation does not appear to have been made. Removing the word "Pilot" would instill greater confidence in the future of the Refinery Investment Credit Program (RICP) and better encourage investment. (WSPA5_FF19-18)

> **Agency Response:** To provide long-term certainty to the RICP, staff modified the Regulation to remove the word "Pilot" from the title of the program, in response to this comment.

L-2.2. *Eligibility to Generate LCFS Credits through Refinery Investment Credit Program*

Comment: Projects that supply Renewable Natural Gas (RNG) to a refinery to displace fossil natural gas, should be eligible to generate LCFS credits through indirect accounting of biomethane as described in section 95488.8(i) ("book and claim accounting for pipeline injected biomethane"), as it is not likely that segregated pipelines

of RNG will be built to supply refineries due to permitting and economic reasons. (WSPA5_FF19-19)

> **Agency Response:** Book-and-claim accounting for pipeline-injected biomethane is allowed for the quantity of RNG that is used as feedstock for renewable hydrogen production in refineries under the Renewable Hydrogen Refinery Credit Program. However, book-and-claim accounting is not recognized for pipeline-injected biomethane to be used as process energy in refineries. This approach has been consistently applied to all other fuel production pathways.

L-2.3. *General Requirements*

Comment: The beginning of the sections reads: *"~~(H)~~(G) Credits generated pursuant to section 95489(e)(1)(D)5.~~(E)(5)~~ may not ~~be~~:"* The term "may not" appears to be applicable to §95489(e)(1)(G)1 and §95489(e)(1)(G)2 but not to §95489(e)(1)(G)3 - *Crediting Periods*, which appears to be mislabeled. WSPA suggests that §95489(e)(1)(G)3 be relabeled as §95489(e)(1)(H). In addition, WSPA suggests the following language change:

> *"Crediting is limited to 15 years from the quarter in which the ~~Executive Officer approves the project's application~~ project is started up."* (WSPA5_FF19-20)

> **Agency Response:** Staff proposed to revise the content of §95489(e)(1)(G) to remove the ambiguity pointed out by the commenter by rewriting this subsection as a whole.

L-2.4. *Refinery Investment Credit Program Credits for Gasoline and Diesel Production*

Comment: ARB proposes a limitation on credit generation for RICP projects (including Carbon Capture & Sequestration and Renewable Hydrogen), using the numerator Volume^{XD}, to limit credit generation to that portion of gasoline and diesel production supplied to the state of California. In order to encourage investment in GHG reduction projects, ARB should remove this limitation and allow credits to be generated for all gasoline and diesel production. This will make additional GHG reduction projects economical and result in real, material progress in reducing refinery emissions based on LCFS credit value. (WSPA5_FF19-21)

> **Agency Response:** Under the LCFS, only fuels that are supplied to California are regulated and earn credits or deficits. To be consistent with this principle, only the California-supplied portion of gasoline and diesel produced at the refinery involving refinery investment credit projects can generate credits.

L-2.5. *Greenhouse Gas Accounting Methodology*

L-2.5a. Comment: REG is concerned about the transparency of this program and its ability to provide real, additional environmental benefits beyond what would be "business as usual." It is our opinion that if a refinery would like to improve their CI

score, they, like alternative fuel providers should conduct a full LCA of their facility and receive a unique CI score. If that CI score is lower than the assumed baseline they can then generate fewer deficits. (REG3_FF44-28)

> **Agency Response:** The GHG accounting method to estimate credit generation under the RICP is based on the life cycle approach. Fundamentally speaking, refinery investment projects are subject to the same level of scrutiny, review, and data requirements as fuel pathway applications.

L-2.5b. Comment: Thanks Anil for the discussion Tuesday on the issue with the RH credit calculation with GREET 3.0. I believe you had mentioned the plan was to change the definitions for the CI_{NG} and CI_{RNG} from "at the refinery gate" to "at the outlet of the SMR", which would then include the production of hydrogen within the SMR in the CI calculation. While there are additional emissions with the step of taking gas to hydrogen, I expected that the CI differential between fossil-based CNG and landfill-based RNG should be the same as the CI differential between fossil-based hydrogen and landfill-based hydrogen.

When I look in the current version of GREET-3.0, I see that the CI of fossil-based CNG is 95.68 g/MJ, and the CI of landfill-based RNG is 64.60 g/M, for a differential of 31.08 g/MJ. When I look at the hydrogen production, I see that the CI for fossil-based hydrogen is 126.16 g/MJ and the CI for landfill-based hydrogen is 114.97 g/MJ, for a differential of 11.19 g/MJ. I believe the difference has to do with the assumption for transport of the natural gas and landfill gas feedstock. For the fossil natural gas, the assumption is 3600 miles for natural gas to CNG but only 1000 miles for natural gas to hydrogen. For the renewable natural gas, the assumption is 1000 miles for landfill gas to CNG but 1600 miles for landfill gas to hydrogen. I believe these two different assumptions in transportation distance are what causes the differential between the two pathways that I described above.

I understand the transportation distance for the landfill gas will be a user input and will be specific to the pathway/ landfill. My concern is that the difference in assumption for transportation distance for fossil gas to CNG versus hydrogen will impact the RH credit calculations. To make the RH credit generation calculation effective, and offer a level playing field between CNG and RH, we'd suggest the language in the definition should say "at the exit of the hydrogen plant, using the same feedstock assumptions for Pipeline Average North American Fossil Natural Gas in pathway code CNGF". You may already have planned to add language to this effect in the definition, but looking at the current GREET model and the discrepancy reinforced for me that this is something that likely needs to be clarified in the regulation. I'm not sure what transportation distance was used to calculate CNGF but it appears that it is closer to 1000 miles versus 3600 miles. I believe using the same transportation distance for natural gas would result in the differential being the same. (IOGEN1_FF36-1)

> **Agency Response:** As pointed out by the commenter, the CI differential between fossil-based CNG and landfill-based RNG is not the same as the CI differential between fossil-based hydrogen and landfill-based hydrogen, primarily

due to a difference in pipeline transportation distance between the fossil CNG and H_2 pathways. To eliminate its impact on credit generation under the Renewable Hydrogen Refinery Credit Program, staff revised the language in a manner suggested by the commenter. As a result, the CI for NG-derived hydrogen will be calculated using the same feedstock/transport assumptions as used for Pipeline Average North American Fossil Natural Gas. This revision in the language will ensure that the distance for transporting NG by pipeline to the SMR facility is the same as the pipeline transportation distance used in calculating the CI of Pipeline Average North American Fossil Natural Gas.

L-2.6. ***Credit Generation Window***

Comment: We are also concerned that the 15-year credit generation window is far too long for most efficiency projects, and that refiners will use this program as a way to subsidize upgrades which would have taken place as a course of normal business. (REG3_FF44-29)

Agency response: In many cases, process improvement projects involve significant lead-time for design and implementation and also require significant capital investments. Many process improvement projects are unlikely to materialize if the crediting period is shorter because project operators would not be able to consider the revenues generated from credits in their financial analysis to justify investments. Staff believes that a 15-year crediting period is appropriate in providing policy certainty for process improvement refinery projects.

Moreover, staff notes that the 15-year crediting window is a limitation placed on petroleum refinery efficiency improvement projects that is not placed on alternative fuel efficiency improvement projects. Alternative fuel producers, such as the commenter, are able to receive credits indefinitely for efficiency improvement projects. In light of this, staff does not believe that allowing petroleum refineries to receive credit for these projects, subject to a 15-year crediting window, is too generous.

L-2.7. ***Credit Generation Transparency***

Comment: We hope that CARB will require transparent disclosure of any credits generated under this program. REG believes that credits from this program should be capped for both efficiency and the renewable hydrogen program (staff should consider something in the range of 5 to a max of 10 percent per obligated party). This will make sure that a substantial part of the market is not eroded away, limiting the incentive for biofuels which have lower tailpipe emissions. (REG3_FF44-30)

Agency response: The application requirements and review of the RICP are as comprehensive as for fuel pathways. The applications are subjected to a public review process by posting them on the CARB website for 10 business days. Staff is committed to providing transparent disclosure of relevant information and

credits generated under the RICP. The credits generated from process improvement projects are subjected to a 10 percent cap and a 15-year credit period. For other innovative projects such as CCS, renewable hydrogen, and renewable electricity, staff does not intend to put a cap on credit generation since the intent of the LCFS is to promote innovative projects involved in fuel production. Given staff's proposal for a 20 percent CI reduction by 2030, staff does not expect that credits generated from these innovative projects will be significant enough to threaten the market and incentives for biofuels.

L-2.8. ***Eligibility and Credit Generation Regulatory Text***

Comment: Staff have proposed a number of provisions which allow refineries to reduce on-site emissions resulting from the production of transportation fuels, subject to certain limits and conditions. We agree that such projects deserve recognition and LCFS credits for the real, quantifiable, additional and verifiable emissions reductions they produce. We suggest a few amendments to clarify the language in these provisions, and ensure that the Executive Officer has the information necessary to make informed determinations about the validity of proposed pathways.

We suggest the following amendments to § 95489 (e) (1) (D) (5)

> 5. Process improvement projects that deliver a reduction in baseline refinery-wide greenhouse gas emissions as outlined in 95489(e)(1)(G)2. Greenhouse gas emissions reductions due to curtailment, simple maintenance; <u>compliance with other statute or regulation, upgrades to meet industry standards</u> and crude oil switching that results in greenhouse gas reductions in the project system boundary 83 without improvements in the processing units or equipment involved are not eligible. For the purposes of this section, curtailment is defined as an intentional operational and/or physical change exclusively for the reduction or cessation of total gasoline and gasoline blendstocks and diesel production at the refinery. Curtailment does not include the coincidental rate reduction or shutdown of associated emitting equipment as part of a process improvement project or projects aimed primarily at optimizing refinery efficiency.

Rationale:

Life cycle analysis, which is the basis of the LCFS, requires that emissions reductions credited to a fuel pathway be additional to what would have happened absent the fuel pathway in question. That is, actions that would have been taken whether or not the LCFS existed are generally not counted towards emissions reductions. The proposed change clarifies that emissions reduction projects undertaken to comply with other statute or regulation, including local air quality programs, are not additional and therefore not eligible for LCFS credit. Similarly, upgrades to bring a refinery up to normal practices within the refining industry are not additional, since they presumably would have occurred without the LCFS.

We suggest moving § 95489 (e) (1) (G) (2) into its own sub-part as § 95489 (e) (1) (H) for clarity

We suggest adding a definition of “Second or higher order effects” as used in § 95489 (e) (3) (A) (4) in an appropriate section of the rule. This definition should include effects on a system or process caused by changes in heat, energy, materials, byproducts or operational parameters in a different system

Rationale:

The proposed language does not give an explicit definition of second or higher order indirect effects which could lead to confusion over the extent of obligation to provide documentation on the part of the pathway applicant under § 95489 (e). The intent of the language is clear: that if a project subject to a refinery investment credit pathway causes significant changes in refinery emissions through indirect effects, these should be considered in the pathway as well. A more explicit definition will reduce the potential for disagreement over what constitutes a second or higher order indirect effect. (NEXTGEN3_FF65-12)

> **Agency Response:** Due to complexity of refinery operations, it is not an easy task to identify industry standards and establish a benchmark for comparison. Equally, it is difficult to monitor and verify if an improvement is undertaken solely for the purpose of complying with other statue or regulation. Due to limited staff resources and staff time, staff is unable to fully evaluate the merit of the suggestion and incorporate it in the current rule making.
>
> Section 95489(e)(1)(G) has been edited to improve the clarity. The second and higher order impacts differ from one project to another. It is difficult to develop a definition that will be applicable for all projects. Staff will review and evaluate each individual project on a case-by-case basis to establish a system boundary and make a determination if second and higher order impacts are significant and warrant their inclusion in the system boundary.

L-3. *Renewable Hydrogen Refinery Credit Program*

L-3.1. *Use of Renewable Energy in Renewable Diesel Production*

Comment: While REG support the spirit of the Renewable Hydrogen Refinery Credit Pilot Program, we disagree with CARB that his program should only be applicable to traditional petroleum refineries. REG believes that not allowing renewable diesel plants to participate puts them at a significant and arbitrary disadvantage. We believe that this inconsistency will provide a significant market advantage for co-processed renewable diesel over standalone renewable diesel production. While California may see life cycle GHG reduction benefits from co-processed diesel, it is unlikely the fuel will provide tail pipe emission reductions. This position is based on our knowledge of fuel quality characteristics and certification, as well as a CARB survey discussing blending habits of RHD in California.

Also, we do not believe this would provide excessive benefit to a standalone facility outside of the state, as a facility would only receive credit for gallons to California. In many ways, we believe this change would encourage more volume of renewable diesel to flow to California rather than other incentivized markets such as Canada or the EU.

CARB should recognize that it is easier for a renewable fuel facility to install renewable electricity generation rather than biomethane production. Biomethane used in hydrogen production needs a complex mix of solid substrates and digestible wastewater to be economical. On their own, renewable fuel plants can't provide that, furthermore, these biomethane plants are most economical when designed for location that produces significant amounts of methane rich waste (dairies, food processing facilities, etc). Therefore, if it makes policy sense to allow refineries to access biodigesters anywhere in the US, it should make the same policy sense for Renewable Diesel facilities.

Finally, we believe this change will help the state reach its short lived climate pollutant goals much quicker by providing an additional market for biomethane as the on-road CNG market is nearly saturated. (REG3_FF44-34)

> **Agency Response:** In response to this comment, staff modified the proposed Regulation to clarify in section 95488.8(i)(2) that book-and-claim accounting can be used for biomethane that is supplied as a feedstock for the production of renewable hydrogen that is subsequently used in the production of an alternative fuel, including renewable diesel produced in stand-alone facilities. Applicants who use renewable hydrogen in renewable diesel production can apply for a new CI by using a Tier 2 application, and the net benefit of using renewable hydrogen in a renewable diesel facility would be similar to using the same renewable hydrogen in a petroleum refinery under the Renewable Hydrogen Refinery Credit Program.
>
> A staff survey of refineries that intend to co-process biomass feedstock suggests that refineries would not compromise the quality of petroleum diesel anticipating the beneficial impact of renewable diesel produced from co-processing. Therefore, staff expects some tailpipe emissions reduction benefits if biomass is co-processed at a 5 percent or higher ratio.
>
> Staff agrees with the comment that allowing the use of renewable hydrogen in a renewable diesel production facility would not provide an excessive benefit to a standalone facility outside of the state. Staff also agrees with the comment that expanding the market for biomethane should help the state reach its short-lived climate pollutant goals quickly.

M. Carbon Capture and Sequestration

M-1. Multiple Comments: *Support for the Proposed Carbon Capture and Sequestration Provisions*

Comment: Additionally, we applaud the efforts that CARB has made to address stakeholder concerns in regards to the financial liability related to the 100 year requirement with the introduction of the 50 yr/5% mandate. This is an innovative approach to insure that the buffer insurance pool can sustain any reversals that could need remediation; however, flexibility in this concept is key. The citations below will tie into a concept of performance based approach to this as well. (WE3_FF22-2)

Comment: Carbon Engineering greatly appreciates the on-going efforts of ARB in operating the Low Carbon Fuel Standard, and recent efforts to develop and implement the CCS Protocol. The California LCFS is a leading example of how effective regulation can drive emissions reductions while accelerating economic growth and preserving affordability of energy products for citizens. The LCFS and the CCS Protocol form an essential market for technologies like CE's to scale up and become mainstream. (CARBONENG1_FF34-1)

Comment: In its 15-Day Modifications, ARB appears to have recognized how important it is that the Protocol reflect the three-dimensional nature of the subsurface environment and the CO_2 plume. In doing so, ARB proposes to replace "area of review" with the concepts and definitions of "storage complex" and "confining system" whenever referring to the three-dimensional storage volume and all geologic layers and structures that impede the lateral or vertical migration of the CO_2 plume. These new definitions, which we support, require operators to fully understand the geology, legacy wells and other leakage risks in the subsurface, thereby strengthening the Protocol and ensuring a higher degree of leakage prevention. (CATFNRDC1_FF55-3)

Comment: We support ARB's proposal to eliminate the requirement for a pressure dissipation interval and a secondary confining layer, and to instead focus on the demonstration of a robust confining system to ensure storage security. As we have explained in previous comments, requiring a pressure dissipation interval and a secondary confining layer does not necessarily enhance storage security, and may in fact result in the selection of a subset of sites with inherently lower security in some cases. (CATFNRDC1_FF55-4)

Comment: We also support ARB's proposal to replace the concept of "pressure front" with areas of "elevated pressure," which far more accurately reflects the more stochastic behavior of pressure in the subsurface. (CATFNRDC1_FF55-6)

Comment: We support the proposed addition to subsection (b) that injection pressure not unacceptably increase the risk of significant induced seismicity. (CATFNRDC1_FF55-7)

Comment: Other areas of substantive improvement that we support include:

- Linking the monitoring, measurement and verification (MMV) to the risk assessment;
- Requiring the operator to submit interpretation of data;
- Ensuring MMV is sensitive to the geologic environment;
- Evaluation of MMV;
- Periodic review of MMV methods; and
- Requiring operators to document their methods.

(CATFNRDC1_FF55-8)

Comment: We support the proposed revision in subsection (b)(1)(C) that corrective action be performed on all wells that may be pathways for CO_2 leakage, including both wells that penetrate the storage complex and wells within the surface projection of the storage complex. As ARB rightly recognizes, shallow wells that do not intersect the storage complex can still become leakage pathways if CO_2 migrates outside the storage complex. (CATFNRDC1_FF55-13)

Comment: We strongly support the proposed addition in subsection (c) that operators be required to provide a description of the completeness of any well record databases relied on to identify wells. The quality of such databases may vary significantly, meaning that they may or may not be reliable as a tool for locating existing wells that may be CO_2 leakage pathways. (CATFNRDC1_FF55-16)

Comment: We support the notion of considering the migration of the CO_2 plume out of the storage complex as "subsurface leakage" (proposed §2(a)(25)). Subsurface leakage indicates that actual operational parameters deviated from the predicted ones, and action should be taken in order to understand the discrepancy and avoid further subsurface leakage in the future. (CATFNRDC1_FF55-18)

Comment: We strongly support ARB's changes in proposed §2.5 that take a more performance- and site-based approach to selecting baseline monitoring techniques, in particular soil gas and atmospheric flux monitoring (revised to a *potential* tool in the 15-day Modifications), while at the same time allowing for methods accompanied by an assessment of sensitivity to detect CO_2 in the natural environment. (CATFNRDC1_FF55-24)

Comment: WSPA sees the CCSP as the roadmap by which successful projects could be permitted and constructed. (WSPA6_FF72-1)

> **Agency Response:** Staff appreciates the support for the CCS Protocol as a whole, as well as the changes that were made to the Protocol in response to the comments submitted during the 45-day comment period.

M-2. Multiple Comments: *Editorial Comments*

M-2.1. Multiple Comments: *Typographical Errors*

Comment: 2.1. Covered Greenhouse Gas Emissions for the LCFS: in the first sentence change “LCSF” to “LCFS” (CATFNRDC1_FF55-33)

Comment: 2.2(f): In the first sentence the phrase “must be evaluated” is repeated twice (CATFNRDC1_FF55-34)

> **Agency response:** Staff thanks the commenters for noting typos in the Protocol language. Staff corrected the errors, as recommended.

M-2.2. Multiple Comments: *Clarifying Edits*

Comment: Given these proposed revisions, we recommend that the use of the term “confining layer” be revised in several places throughout the protocol:

2.1(a)(3) the phrase “confining layer” should be revised to read “primary confining layer.”

2.3(a)(2)(A) the phrase “confining layer” should be replaced with the term “confining system.”

2.3(a)(2)(B) the phrase “confining layer” should be replaced with the term “confining system.”

2.3(a)(3)(B) the phrase “confining layer” should be revised to read “confining layer(s).”

2.3(a)(3)(C) the phrase “confining layer” should be revised to read “confining layer(s).”

2.3(a)(3)(E) the phrase “confining layer” should be revised to read “primary confining layer.”

2.3(e)(1) the phrase “confining layer” should be revised to read “primary confining layer.”

2.3(g) the phrase “confining layer” should be revised to read “primary confining layer.”

2.3(k)(5) the phrase “confining layer” should be replaced with the term “confining system.”

2.4.1(a)(1)(C)(3) the phrase “confining layer” should be revised to read “confining layer(s).”

3.1(c)(1)(G) the phrase “confining layer” should be revised to read “confining layer(s).”

3.1(c)(3) the phrase “confining layer” should be revised to read “confining layer(s).”

3.2(e) the phrase “confining layer” should be revised to read “confining layer(s).”

(CATFNRDC1_FF55-5)

Comment: We also propose that subsections (b)(1) and (b)(2) be combined to reduce redundancy, as follows:

(1) Identify all artificial penetrations, including all wells that either penetrate the storage complex or are within the AOR, and provide a tabulation of each well's type, construction, date drilled, location, depth, record of plugging and/or completion~~,~~; casing diagrams for those wells pursuant to subsection C.2.4.3.1; and any additional information the Executive Officer may require;

~~(2) Identify all wells that either penetrate the storage complex or are within the AOR, and provide casing diagrams for those wells pursuant to subsection C.2.4.3.1; and~~

(CATFNRDC1_FF55-15)

Comment: We believe §2.4.4 should be titled "Storage Complex Reevaluation" – not "Plume Reevaluation." The plume is a physical occurrence, not a regulatory construct. (CATFNRDC1_FF55-19)

Comment: There appear to be significant overlaps in the requirements of §§4.1(a)(9) and 4.1(a)(12). We recommend that ARB consolidate these two subsections or else clarify how the requirements differ. (CATFNRDC1_FF55-27)

Agency Response: Staff agrees with the commenters' suggested edits that clarify the Protocol and reduce redundancy. In response, staff modified the Protocol following the recommendations of comments CATFNRDC1_FF55-5 and CATFNRDC1_FF55-15.

Staff agrees with comment CATFNRDC1_FF55-19, in that the plume is a physical property, and therefore, staff changed the title of subsection C.2.4.4, as suggested.

Staff also agrees with comment CATFNRDC1_FF55-27 concerning overlapping requirements within subsection C.4.1, and thus, staff combined subsections C.4.1(a)(9) and C.4.1(a)(12), as recommended.

M-2.3. Multiple Comments: *Definitions*

Comment: The definition of "storage complex," (proposed §2(a)(48)) should be modified as follows, to take into account the universal definition of risk as Probability x Consequence, and the fact that risk can be infinitesimally small although technically not zero.

"Elevated pressure" means the fluid response to CO_2 injection is such that the pressure rise creates an unacceptable risk of CO_2 or brine leakage.
(CATFNRDC1_FF55-9)

Comment: As currently written, these two terms have the same meaning, i.e. the volume of void space in rocks or soil. In practice, the term "pore space" is used in the draft Protocol to refer to the voids themselves, not their total volume. As such, we recommend the following revisions:

2(a)(88) "Pore space" means the ~~volume between crystals or grain~~voids in a rock or soil that can be filled by a fluid, such as water, air, or CO_2.

2(a)(89) "Porosity" means the ~~relative~~ volume percentage of pore space. (CATFNRDC1_FF55-10)

Comment: We request that ARB clarify the definition of "plume stabilization," at proposed §2(86). The definition remains unclear as to whether or not plume stabilization is synonymous with a static system that is in equilibrium with the surrounding rock in the storage formation or whether it allows for a demonstrable statistical trend towards subsurface pressure equilibrium and permanence of the injected CO_2, a concept we advocated for in our 45-day comments. We are particularly concerned that demonstrating complete equilibrium with the subsurface within a 100-year period may not be feasible, or indeed useful, in many geologic settings. Moreover, "small" is undefined and relative, and "certainty" is more precisely defined in relation to the risk of leakage. We recommend the following definition for plume stabilization:

2(86) "Plume stabilization" means that the rates of plume migration and pressure changes have decreased such that monitoring and predictive methods demonstrate that there is minimal risk of leakage over a 100-year period with a very high degree of certainty. (CATFNRDC1_FF55-22)

Comment: Delete definition §2(2) "Area of Review". The use of this term may lead to confusion and we recommend that everywhere it is used it be replaced with the phrase "the surface projection of the storage complex." (CATFNRDC1_FF55-32)

Agency Response: In regards to the definitions of "storage complex" or "plume stabilization," staff disagrees that the definitions need further clarification, or that the suggested edits to the text would improve that clarity. Therefore, these definitions were not modified in response to the comments.

In regards to comment CATFNRDC1_FF55-10, staff agrees with the commenter that the definition of "pore space" and "porosity" were equivalent, and thus, staff modified the definitions according to the suggestions from the commenter.

In regards to comment CATFNRDC1_FF55-32 concerning the term "area of review," staff agrees that the term may lead to confusion, especially in the context of the updated definition of "storage complex," which incorporates the three-dimensional storage volume and overlying confining system. Therefore, staff replace "area of review" throughout the document with "the surface projection of the storage complex," as suggested.

M-2.4. Multiple Comments: ***Suggested Edits Not Incorporated***

Comment: We recommend that subsection (b)(1) be revised to require operators to "Use best available methods and technologies to" identify all artificial penetrations. This would provide a recognition that it may not be technologically feasible to identify "all" artificial penetrations, while still maintaining a high standard that all available efforts be made to do so. (CATFNRDC1_FF55-14)

Comment: We note, however, that this change is still not reflected in Figure 5. As written, the flowchart states that if records indicate the presence of abandoned wells and if those records indicate the wells are properly plugged, then the well evaluation process is complete. A critical step is missing, which is requiring the operator to determine whether those well records are actually sufficient to locate all existing wells and determine whether they're adequately plugged. We request that an additional box be added to the flow chart that reflects the proposed additional language in subsection (c). (CATFNRDC1_FF55-17)

Comment: We believe that the requirement for monitoring of all wellbores at proposed §4.3.2.2(e) is unnecessary. During the operational phases of injection, the operator would notice a drop in injection pressure at the injection wellhead in the event of CO_2 and related brines reaching the surface. Operators are already required to continually monitor mechanical integrity (§4.2(c)) and determine whether a release may have occurred if mechanical integrity may be compromised (§4.2.2). If an operator suspects a loss of mechanical integrity, it should be immediately required to cease injection, and go to the field to inspect all wellbores potentially affected, whether they be production wells or legacy wells. Therefore, we recommend that this requirement be revised as follows such that surface inspection and CO_2 flux monitoring be required in the event of a loss of mechanical integrity or other indicator of well failure:

> 4.3.2.2(e) Monitoring of all wellbores: When loss of mechanical integrity is detected the CCS Operator must investigate ~~monitor~~ all potentially affected wells within the storage complex. ~~Monitoring should include direct observation of the wells, if possible, and surface air monitoring around the wellbore.~~ Where leakage is suspected, monitoring should be considered ~~focus on identifying CO_2 flux~~ in the vicinity of ~~the~~ potentially compromised wellbore ~~that may indicate a catastrophic leak~~. (CATFNRDC1_FF55-28)

> **Agency Response:** In regards to comments CATFNRDC1_FF55-17 and CATFNRDC1_FF55-28, staff disagrees with the commenters' suggestion that the Protocol should be revised to lower the standard for corrective action and monitoring. Identifying and monitoring all wells that intersect the storage complex is one of the most basic, fundamental components to securing storage and achieving permanence. To remove this basic standard would compromise the environmental integrity of the Protocol. Prevention of leakage should be prioritized such that mitigation is unnecessary. Identifying and monitoring all wells support this position.

Regarding comment CATFNRDC1_FF55-14, the Protocol was designed on the premise that operators use the best available technology. It is unnecessary to include this provision explicitly.

In regards to comment CATFNRDC1_FF55-17 concerning Figure 5, in some cases, it is known that wells were drilled prior to the maintenance of well records, and therefore, it is expected that there would exist some wells in certain locations that are undocumented. Still, CCS operators must make every effort to identify both documented and undocumented wells. Figure 5 is clear as-is, and would not be improved by the suggested comment, therefore, staff made no modifications to Figure 5 in response to the comment.

M-3. Multiple Comments: *100-Year Post-Injection Site Care*

Comment: C.5.2(b)(2). After injection is complete, the CCS Project Operator must continue to conduct monitoring as specified in this section and the Executive Officer approved Post-Injection Site Care and Site-Closure Plan for a minimum of 100 years.

We understand that CARB proposes a 100-year post injection monitoring period to ensure that permanence can be demonstrated. Several authors have found that the critical monitoring period is 20-years post injection.[2] Beyond 20 years, the risk of a release from a subsurface reservoir declines asymptotically to near zero with time. We suggest that a performance standard approach is a preferred course of action. CCS Project Operators should have a range of options to demonstrate permanence, including:

- After 20 years, full closure of all penetrations into the sequestration zone, including monitoring wells, and the posting of a financial instrument accounting for the remaining 80 years of potential post closure liability, to ensure coverage in the event of an unforeseen event, e.g., a natural disaster, that results in a loss of some amount of CO_2 from the reservoir;
- An opt-out option transferring liability to the state and the use of a separate LCFS buffer account or some other financial instrument; or,
- Where permitted by state law, transfer liability to the state, e.g., as in Montana

[2] See, e.g., Anderson, Steven T., (2017). Risk, Liability, and Economic Issues with Long-Term CO_2 Storage – A Review. Natural Resources Research, 26(1), 89, 93CO.

(OCCIDENTAL3_FF1-18)

Comment: Modify

§5.2(b)(2) from: *"After injection is complete, the CCS Project Operator must continue to conduct monitoring as specified in this section and the Executive Officer approved Post-Injection Site Care and Site Closure Plan for <u>a minimum of 100 years</u>."*

To:

"After injection is complete, the CCS Project Operator must continue to conduct monitoring as specified in this section and the Executive Officer approved Post-Injection Site Care and Site Closure Plan for the minimum time specified in the approved post injection site care plan." (WE3_FF22-3)

Comment: Modify

Definition (99) from: *'"Site closure" means the point or date, after at least 100 years and as determine by the Executive Officer following the requirements under subsection C.5.2, at which point the CCS Project Operator is released from post-injection site care responsibilities.'*

To:

'"Site closure" means the point or date, equal to the lessor of 100 years after and as determined by the Executive Officer following the requirements under subsection C.5.2, at which point the CCS Project Operator is released from post-injection site care responsibilities or functional equivalence of 100 years of permanence has been met as determined by the Executive Officer.' (WE3_FF22-4)

Comment: Modify

§5.3(F) from *"The CCS Project Operator must conduct leak detection checks at each well that is part of the CCS project, and in the near surface close to each plugged and abandoned well, every five years for 100 years after injection is complete, minus the time it takes for the CO_2 plume to reach stability. Monitoring must include:"*

To:

The CCS Project Operator must conduct leak detection checks at each well that is part of the CCS project, and in the near surface close to each plugged and abandoned well, every five years post injection for the lessor of 100 years after injection is complete or the time frame in which functional equivalence of 100 years is met as stated in the post injection site care plan, minus the time it takes for the CO_2 plume to reach stability. Monitoring must include: (WE3_FF22-5)

Comment: We do not oppose the concept of 100 years as the benchmark for which CO_2 must be kept from the atmosphere to insure reductions in global climate change potential, however the language of the protocol is too literal in the interpretation of 100 years. An example of which is §5.2(b)(2) "*After injection is complete, the CCS Project Operator must continue to conduct monitoring as specified in this section and the Executive Officer approved Post-Injection Site Care and Site Closure Plan for a minimum of 100 years*." The following citations will illustrate that 100 years of monitoring is not required if a level of functional equivalence can be reached. The core argument that staff has had to 100 years of monitoring is that assurance must be reached in the protocol that the CO_2 is entrained and separated from the atmosphere,

this argument is not in question; but the assertion that a literal 100 years must pass in order to prove that the CO_2 does not make it back into atmosphere is overly conservative. Overly extensive monitoring requirements and timeframes could hamper participation in the CCS protocols as project developers could have few options for development of the surface once injection has ceased but still have to maintain access and equipment for monitoring as required for a lengthy period of time as the protocol suggests. (WE3_FF22-1)

Comment: We recognize the significant effort staff have made in improving the proposed carbon capture and sequestration (CCS) protocol. CARB staff are breaking new regulatory ground and building a foundation which could support early deployment of a technology which may be a crucial tool to mitigate climate change. For the most part, we echo the comments the Clean Air Task Force and the Natural Resources Defense Council are submitting in this comment period, regarding several technical issues which were addressed in the Modified Text.

Specifically, **we agree that the blanket application of a 100 year monitoring requirement is unscientific, insensitive to the conditions at the injection site, and presents a massive deterrent to developers considering first-generation commercial projects**. Since post-injection monitoring will almost certainly not begin on any project until the 2040's or 2050's at the earliest, defining appropriate post-injection monitoring protocols now ignores the decades of likely technological progress.
100 years of post-injection surface monitoring may provide very little reassurance that there has been no atmospheric leakage when compared to subsurface or atmospheric monitoring approaches. The 100 year surface monitoring requirement imposes massive costs to any project developer, which creates an obstacle to financing projects.

We also agree with CATF and NRDC that unexpected subsurface migration of injected carbon dioxide should not invalidate CCS credits, provided that such migration does not lead to atmospheric release. **Monitoring should be designed to be geographically and geologically appropriate to ensure no atmospheric leakage has occurred** and not focused on whether subsurface behavior matches the predictions of current models.

Given the lack of real-world experience with CCS, we recognize that the first generation of commercial scale projects will entail real, though probably not substantial, risk that the stored carbon could escape. We commend Staff for the thought and effort they have made to design a program which can manage this risk. Given the critical need to deploy CCS at commercial scales, it may be prudent for CARB to temporarily adopt a view of risk that diverges from precedent, for the first few projects which utilize this pathway. Because of the immense uncertainty regarding first-generation commercial-scale CCS projects, when risk is accurately priced into development costs, projects may become too expensive for any developer to accept, even after considering the value of LCFS credits. CARB may wish to consider absolving developers of the first small handful of projects of much of the credit reversion risk in order to ensure that those projects move forward and begin to develop the corpus of real-world experience necessary to support expansion of CCS at a pace capable of meeting global climate targets. For example, CARB may wish to exempt the first few projects from credit

reversion risk except in the case of negligence or malfeasance. Any such re-evaluation of risk should be contingent on project developers adhering to the highest possible quality standards during project development and a high level of transparency regarding project design and performance. This exemption from normal risk-management protocols should be strictly limited in both scope and duration. In essence, CARB may wish to consider a more permissive approach to the first handful of pilot projects which can help inform the development of more robust and empirically-supported future CCS policy. While this means California will accept the risk that emissions from a leak at a CCS project could increase future emissions, the potential payback from developing CCS technology to commercial viability is so great that an exception may be warranted in this case. (NEXTGEN3_FF65-13)

Agency Response: Please see Response M-6 in Chapter IV.

M-4. Multiple Comments: *Post Injection Site Care*

M-4.1. Multiple Comments: *Well Plugging and Abandonment Plan*

Comment: C.5.2(b)(3)(A). Within 24 months after site injection is complete, all injection (and production, if applicable) wells associated with the CCS project must be plugged and abandoned pursuant [sic] subsection C.5(d), with the exception of any wells that the CCS Project Operator plans to transition into observation or monitoring wells.

In the course of operation, CO_2-EOR projects may repeatedly convert CO_2 injection wells to water injection wells and then return the wells to CO_2 injection. Requiring plugging and abandoning of such wells is not necessary and does not reflect the nature of CO_2-EOR operations. In addition, we read this requirement as not being triggered until the entire site enters into the Post-Injection Site Care period. To provide clarity, we suggest the following revision:

C.5.2(b)(3)(A). "Within 24 months after the CCS Project enters into the Post-Injection Site Care period, all injection (and production, if applicable) wells associated with the CCS project must be plugged and abandoned pursuant to subsection C.5(d), with the exception of any wells that the CCS Project Operator plans to transition into observation or monitoring wells." (OCCIDENTAL3_FF1-15)

Comment: C.5.2(b)(3)(A) requires all injection (and production, if applicable) wells associated with the CCS project to be plugged and abandoned pursuant to C.5.1(d), with the exception of any wells that the CCS Project Operator plans to transition into observation or monitoring wells.

We understand CARB's intent here as ensuring that upon closure, a CCS Project Operator will ensure safe and permanent storage of CO_2. A properly designed and operated CO_2-EOR project will provide this safe and permanent storage.

To optimize production, CO_2-EOR operations will adjust operations throughout the life of a field. At this time, operations will include an extended period of CO_2 injection that

may be followed by water injection, or a water chase. Currently, Occidental is planning to conduct enhanced oil recovery by injecting CO_2 into its reservoirs for several more decades, in some cases into 2100. At that time, Occidental will convert portions of its fields to a water chase operation and still produce oil, which will have some CO_2 entrained. As required by the protocol, Occidental will be required to calculate the CO_2 entrained in the oil and account for it in its LCFS credit. When oil production from the reservoir is complete, Occidental will enter into the Post-injection site care period pursuant to C.5.2. We request that the protocol recognize this operating scenario and suggest the following revision:

C.5.2(b)(3)(A) "Within 24 months after injection is complete, all inactive injection wells associated with the CCS project must be plugged and abandoned pursuant to subsection C.5.1(d), with the exception of any wells that the CCS Project Operator plans to transition into observation or monitoring wells or to operate for continued oil and gas production." (OCCIDENTAL4_FF37-13)

> **Agency Response:** Staff agrees with the commenter's suggestion to clarify that injection wells must be plugged and abandoned after the CCS project enters into the post-injection site care period. Staff revised subsection C.5.2(b)(3)(A) of the Protocol as suggested in OCCIDENTAL3_FF1-15. Although staff did not make the specific revisions suggested in OCCIDENTAL4_FF37-13, staff believes the above clarification made in the Protocol addresses the commenter's concern by clarifying that only wells which have entered the post-injection site care period are required to be plugged and abandoned. Additionally, subsection C.2.3.1(c) of the Protocol allows for the transitioning of an injection well to a monitoring well, which would negate the issue of plugging un-used wells.

M-4.2. Multiple Comments: *Concerns with Post Injection Prescriptive Monitoring Requirements*

Comment: In addition, it still requires 100 years of post-injection site care (PISC). The WSPA comment letter of April 23, 2018 on the CCSP portion of the Proposed Low Carbon Fuel Standard Regulation Amendments clearly expressed that these proposed leakage risk ratings are an arbitrary construction that has no basis in any CO_2 geological storage technical literature, expert opinion, or legal "precedent".[1] ARB neither cites nor even provides a correct interpretation of the examples in the putative Special Report on Land Use, Land Use Change, and Forestry (SR-LULUCF) analog from the Intergovernmental Panel on Climate Change.

[1] While ARB staff has cited legal and technical reasons to treat CCS the same as forestry, there is no legal nor technical basis justifying the same treatment: https://www.arb.ca.gov/lists/com-attach/127-lcfs18-VjpQN1QhUmkGYQdq.pdf

ARB also seeks to require a guaranteed additional credit reserve of 5% of total stored CO_2 to cover the risk of up to 100% reversal during the period from 50 years after injection has ceased up to 100 years after injection has ceased. The premise of 100% reversal is flawed. Only in very specific cases would it be even theoretically possible to get up to one-half back (e.g., structurally-closed depleted gas fields as opposed to "open", dipping reservoirs)[2] or, conceptually, from gas caverns.

[2] Snippe & Tucker, CO_2 Fate Comparison for Depleted Gas Field and Dipping Saline Aquifer, Energy Procedia, December 2014

WSPA continues to believe that the actual risks are substantially lower and the credit bank imposed by ARB is excessive.

WSPA suggests the following alternatives to the PISC requirements for ARB consideration:

Alternative 1. For the post-injection site care (PISC) and site closure requirements to address activities that occur following cessation of injection: The owner or operator must continue to monitor the site for up to 100 years following the cessation of injection, or as approved by the EO, an alternative timeframe, until it can be demonstrated that plume stability has been achieved and no additional monitoring is needed to ensure that the project does not pose an endangerment to the atmosphere or subsurface resources; following this, they must plug the injection and monitoring wells and close the site.

Alternative 2. For the post-injection site care (PISC) and site closure requirements to address activities that occur following cessation of injection: The owner or operator must continue to monitor the site for up to 100 years following the cessation of injection or after a review period as outlined below. The 100 years will include a review every 25 years after cessation of injection, an assessment of plume stability status, for which if it is demonstrated that CO_2 plume migration and pressure changes are small and predictable, no additional monitoring is needed to ensure that the project does not pose an endangerment to the atmosphere or protected subsurface resources. The owner or operator must plug the injection and monitoring wells and close the site.

Alternative 3. The post-injection site care (PISC) and site closure requirements address activities that occur following cessation of injection: The owner or operator must continue to monitor the site for up to 100 years following the cessation of injection until it can be demonstrated that plume stability has been achieved; following this, the owner or operator must plug the injection and monitoring wells and close the site. Periodic aerial survey inspections at 5-year intervals would be conducted to ensure continued mechanical integrity of the plugged system.
(WSPA6_FF72-3)

Comment: CATF and NRDC remain concerned that ARB has thus far declined to make significant improvements to the post-injection monitoring provisions. As currently proposed, these provisions do not afford the degree of environmental protection that is feasible, and are insufficiently informed by today's best science and practices. Failing to address the problematic aspects of the post injection monitoring provisions weakens the performance-based approach of the revised Protocol, and detracts from its effectiveness in protecting the environment and credibility. We strongly encourage ARB to revisit these aspects of the Protocol. (CATFNRDC1_FF55-2)

Comment: We continue to have serious concerns with the proposed post-injection site care and monitoring regime. With the proposed 15-day Modifications, ARB's approach to post-injection monitoring can be summarized as follows:

- Intensive monitoring is to take place as soon as injection stops and until plume stabilization has been successfully demonstrated.
- Plume stabilization may not be demonstrated earlier than 15 years after injection stops.
- After plume stabilization has been successfully demonstrated, leak detection checks are to take place until 100 years after injection have elapsed, consisting of the following at a 5-year frequency:
    - Soil-gas and surface-air monitoring at and near former wellheads or well pads;
    - Visual inspection of the land surface near former wellheads or well pads; and
    - Inspection of potential pathways highlighted in the risk assessment for the preferential migration of CO_2 or brine to the surface, followed by more intensive monitoring if such inspections give reason for concern.

ARB rightly recognizes plume stabilization as the more important and resource-intensive task, and appropriately requires a significant effort to prove that such stabilization has occurred. However, there are several problems with the approach after that point.

First, as we have extensively documented in previous comments, soil-gas and surface-air monitoring techniques have been shown to be inaccurate, unreliable, and prone to influences from several external factors that are irrelevant to the security of storage. We continue to recommend that, if the objective is to detect CO_2 fluxes at the surface, a more general class of methods should be required, such as surface- and near-surface detection methods. Mandating problem-prone monitoring methods weakens oversight. We therefore again encourage ARB to rely on the use of at-depth monitoring methods that have been shown to detect CO_2 leakage, or the potential for leakage, sooner and much more reliably, and to place greater credence on the results of these methods.

Second, and along similar lines, visual inspections of the land surface near former wellheads or well pads may only be effective in detecting large leaks under limited circumstances where there is ample and sensitive vegetation that is unaffected by other factors such as seasonal or other temporal variations, stress due to drought or weather, etc. Although easy enough to perform, this requirement creates the impression of diligence, but provides only the most rudimentary protection.

Third, although the proposed addition of inspection of potential pathways highlighted in the risk assessment for the preferential migration of CO_2 or brine to the surface, followed by more intensive monitoring if such inspections give reason for concern is a sound concept, it must be appropriately timed and prescribed. The type of “inspection” is also not specified. We believe that such a requirement is appropriate and desirable until such time as it is proven with a very high degree of confidence that no such migration is possible. Prescribing it on a perpetual basis is unnecessary given the

extensive monitoring, risk identification and mitigation measures that comprise the Protocol.

Taken together, these points fall short of achieving the highest level of environmental benefit or scientific integrity. In fact, ARB staff's response to Board Member Judy Mitchell's query at the April 27th, 2018 Board meeting query on the soundness of the 100-year monitoring provision gives us further cause for concern. The response[1] states precedent in the Forestry Offset Protocol and consistency with that as the primary reason for the existence of the same provision in the CCS Protocol, and proposes a decrease in the frequency of monitoring as a way to address concerns about the requirement's soundness and workability. CATF and NRDC have submitted detailed comments[2] previously, extensively demonstrating that forestry and CCS projects are substantially different. While both types of projects can be held to a consistent level of permanence, the requirements imposed on them to demonstrate permanence must be specific to the nature of the projects, and hence fundamentally different.

[1] Industrial Strategies Assistant Division Chief Sahota, Meeting, State of California Air Resources Board, Transcript, at 250-51 (Apr. 27, 2018) available at: https://www.arb.ca.gov/board/mt/2018/mt042718.pdf?_ga=2.108898882.1568586200.1530205962-927216373.1510684661.

[2] Coalition Comments on Draft CCS Accounting and Permanence Protocol and on Draft Regulatory Amendments to the Low Carbon Fuel Standard as these pertain to CCS technology, (Dec. 4, 2017) *available at:* https://www.arb.ca.gov/fuels/lcfs/workshops/12042017_coalition.pdf.

In addition to the different nature of forestry and CCS projects themselves, ARB's regulatory approaches to the two classes of projects is starkly different. Under the Forestry Offset Protocol, leakage risk mitigation is absent, and ongoing monitoring and accounting of carbon stocks is both appropriate and desirable. In sharp contrast, the CCS Protocol is the largest collection of preventative, risk identification and mitigation provisions for CCS conceived by any jurisdiction to date. We commend ARB for pursuing the laudable goals of protecting public health and the environment. However, ARB needs to remain open to the possibility that this multi-layered approach to shrinking risk down to the bare minimum will actually succeed – something that the current post-injection monitoring requirements portray is not the case.

In addition, the proposal to decrease (or, to increase) the frequency of the monitoring prescribed over the 100-year period without a provision to consider site-specific parameters, is unsound and risks prolonging the time during which a potential leak remains undetected. For example, if human activity at the surface interferes with a well component and causes a leak, this could go undetected for a longer period if the frequency of checks is decreased. A default number is of little use in the complex universe of a CCS project. What is important is to assess whether there is residual risk of leakage throughout the 100-year period, what monitoring methods are best suited to establishing such risk, and the degree of confidence. Using the example above, if well components are vulnerable to human activity at the surface and no definitive means exist to prevent interaction, then ongoing monitoring would be warranted. If, however, by physical, electronic (note that we are contemplating technology many decades from today when these provisions would theoretically kick in) or other means such interaction is guaranteed to be avoided, then no further monitoring would be necessary. We do not

contend that the number “100” should simply be replaced by another, or smaller, number. Nor do we contest the definition of permanence in the context of the LCFS, which requires CO_2 to remain underground for 100 years – we believe that this performance level will be easily achieved or even greatly exceeded for the vast majority of injected CO_2. Instead, we propose that the Executive Officer have authority to require post-injection monitoring to continue for up to 100 years if necessary, while also having the authority to approve site closure earlier if no remaining doubts exist on the security of storage.

Our alternative does not require an affirmative belief today that no leakage is ever possible after a certain point, or in every case. It merely requires leaving open the possibility that technology and understanding many decades from now will have advanced to the point that will enable us to make such statements with a very high degree of certainty. For example, earthquakes have been cited as a possible reason for CO_2 leakage. In 2004, a 6.8-Richter scale earthquake took place 20km from a CO_2 injection site in Nagaoka, Japan. The injected CO_2 has been monitored by scientists before, during and after the earthquake and no leaks have been detected to date.[3] Today, this forms the basis for a hypothesis that earthquakes may not be an a priori concern to the integrity of sequestration sites. However, this hypothesis will need to be tested on a case-by case basis taking into consideration geologic and tectonic setting as well as well construction.

[3] Comment letter CATFNRDC1_FF55 did not include footnote 3

We do consider it perfectly plausible though that such studies will have been performed many decades from today. We are not contending that modeling or predictions should be used in lieu of real evidence or observations. On the contrary, we believe in using concrete evidence. As another example, Porse et al.[4] assess the risk of a well blowout to be on the order of 10^{-3}, with the relevant sample space being Railroad Commission districts in Texas. Others assess the risk to be two orders of magnitude lower (10^{-5}) based on offshore wells in the UK, highlighting that location and regulation can play an important part in mitigating risks.[5] These studies represent statistical evidence, based on experience and observation – not modeling or conjecture. Categorically believing that the existence of such evidence will be impossible is unfounded. It is also paradoxical that ARB believes that 15 years may sufficient to make the more involved and complex demonstration of plume stabilization, but apparently does not consider it possible that residual leakage risk can also be shown to be minimal or non-existent at some point during the 100-year period.

[4; 5] Comment letter CATFNRDC1_FF55 did not include footnotes 4 or 5

We also point out that these post-injection monitoring requirements are almost certain not to be applied in practice in the later years, for the very simple reason that many decades from now both the CCS Protocol and the LCFS program will likely have been succeeded and superseded by other requirements and programs. With that in mind, we strongly urge ARB to consider the side effects that such requirements may have at the present time in California and other jurisdictions. Our organizations believe that CCS can meaningfully complement other greenhouse gas reduction strategies and have long argued that it be required for certain types of facilities through performance standards

and other regulations. However, we are concerned that if the Protocol is finalized in its current form, the provisions we highlight as problematic may impose additional actual and/or citable hurdles to requiring broader and more expedited installation of CCS in California and nationally, at no environmental benefit.

Our proposed approach avoids these pitfalls while affording a greater degree of environmental protection. It allows for post-injection monitoring to extend to the full 100 years if needed, using tools that are specific to the situation and known to be effective, with monitoring to be performed at a frequency best suited to the situation as opposed to a "one-size-fits-all number". Specifically, we recommend the following changes:

2(a)(91) "Post-injection site care and monitoring period" means the time between the date of injection completion and ~~100 years after injection completion~~ until the Executive Officer has authorized site closure.

2(a)(101) "Site closure" means the point or date, ~~after at least 100 years and~~ as determined by the Executive Officer following the requirements under subsection C.5.2, at which point the CCS Project Operator is released from post-injection site care responsibilities.

5.2(b)(2) After injection is complete, the CCS Project Operator must continue to conduct monitoring as specified in this section and Post-Injection Site Care and Site Closure Plan for up to ~~a minimum of~~ 100 years~~.~~ and until such time as the Executive Officer approves a demonstration by the CCS Project Operator that project monitoring and modeling data, and other evidence, show with a very high degree of confidence in achieving permanence following the cessation of injection.

5.2(b)(3)(G) The CCS Project Operator must implement a leak detection strategy ~~at~~:

1. ~~and i~~In the near surface strategically located near plugged and abandoned project wells; and
2. At ~~A~~areas of concern informed by the risk assessment (following subsection C.2.2) as potential pathways for the preferential migration of CO^2 or brine to surface,
3. ~~, every five years~~ during the post-injection site care and monitoring period at a frequency based on monitoring and verification data collected during injection and using methods approved by the Executive Officer. ~~Monitoring must include:~~

~~1. Soil-gas and surface-air monitoring at, and within 10 ft of, the former wellhead or well pad;~~

~~2. Visual inspection of the land surface within a 100 ft radius of the former wellhead or well pad; and~~

~~3. must be inspected.~~

If the ~~inspection~~ checks suggest~~s~~ a potential leak may have occurred, the area must be tested pursuant to subsection C.4.3.2. (CATFNRDC1_FF55-31)

Agency Response: Regarding the 100-year timeline for post-injection site care, please see Response M-6 in Chapter IV. Regarding the premise of 100% reversal, the CCS protocol was designed to be conservative, and as such, the provisions were designed to be flexible enough to account for any amount of leakage if it occurs, and rigorous enough to reduce the likelihood of any leakage to a minimal level. In response to WSPA's recommended alternatives to the 100 year monitoring provision, Staff evaluated option three and modified the Protocol to allow aerial review of the project site post-plume stabilization if the aerial method is shown to be equivalent to or better than on the ground surveys.

Regarding future updates to monitoring, including PISC monitoring, as part of Board Resolution 18-34, which approved the amendments to the LCFS regulation, including the CCS provisions and CCS Protocol, the Board directed the Executive Officer to monitor development of the CCS Protocol under the LCFS and to propose technical updates to the CCS Protocol, including the monitoring requirements, as needed. Staff will continue to monitor the latest science on this mechanism and propose technical updates to the CCS Protocol, as appropriate.

In response to the commenter's suggestions regarding 5.2(b)(3)(G), staff made modifications to allow for aerial monitoring, and to remove focus from soil gas monitoring to having operators develop a leak detection strategy, leaving soil gas monitoring a potential component of the strategy. Staff also modified the data collection provisions to focus on the types of data needed, rather than the methods of data collection. Staff did not make the other changes suggested by the commenters, because they did not clarify or correct the specific provisions in the CCS Protocol, and in some cases would reduce the level of stringency.

M-4.3. *Plume Stabilization and Well Closure*

Comment: The application of the concept of plume stabilization is important as well. We recommend a small modification in the language of proposed §5.2(b)(3), in order to allow for a demonstration that includes both monitoring and modeling, as follows:

5.2(b)(3)(B) Monitoring and observation wells may remain open, and in active monitoring mode, until CARB approves a ~~determines that~~ plume stabilization determination ~~has occurred~~. (CATFNRDC1_FF55-23)

Agency Response: Staff agreed that a modification to the language was necessary, but staff did not agree with the change proposed by the commenter. Staff modified the language such that the Executive Officer approves an operator's demonstration of plume stabilization, which is a stronger standard, and less ambiguous than approving an operator's determination of plume

stabilization. The updated language requires the operator to submit a demonstration, including data, evidence, and interpretation of plume stability.

M-5. Multiple Comments: *Buffer Account*

Comment: Section § 95490(h)(3) introduces a new approach to credit retirement 50-years post-injection.

Occidental understands that some project operators may be uncomfortable with a 100-year post-injection liability. Other operators, Occidental included, with mature CO_2-EOR fields, have analyzed the likelihood of a release from a CCS Project and have determined that the chance of a release is vanishingly small. In consideration of those operators that favor a shorter limit to their long-tail liability, Occidental proposes that CARB retain the option that a CCS Project Operator may opt into a 50-years post-injection liability approach in exchange for a 5% increase in their contribution to the buffer account. However, Occidental proposes that CARB retain the initial approach as an option for those CCS Project Operator's that are comfortable with a long-tail liability of 50-years post-injection.

Occidental suggests the following revision to provide for this option:

§ 95490. [Reserved.] Provisions for Fuels Produced Using Carbon Capture and Sequestration.

(h) CO_2 Leakage and Credit Invalidation.

(1) Credits for verified GHG emission reductions can be invalidated if the sequestered CO_2 associated with them is released or otherwise leaked to the atmosphere.

(2) The number of invalidated credits is equal to the quantity of CO_2 released or leaked from the sequestration zone, which must be determined in accordance with the CCS Protocol.

(3) A project operator must select one of the following options

(A) Prior to 50-years post-injection:

(i) The Executive Officer may retire credits from the buffer account, up to and including the project's total contribution, to count toward the number of invalidated credits.

(ii) The project operator must retire credits for any balance after retiring credits pursuant to 95490(h)(3)(A).

(iii) The Executive Officer may retire credits from the buffer account equivalent to remaining outstanding balance after retiring credits pursuant to 95490(h)(4)(3)(A) and (B).

(B) After 50 years post-injection:

(i) The project operator is no longer responsible to make up any credits found to be invalid due to leakage.

(ii) The Executive Officer may retire credits from the buffer account to cover any credits found to be invalid due to leakage.

(C) Prior to 100-years post-injection:

(i) The Executive Officer may retire credits from the buffer account, up to and including the project's total contribution, to count toward the number of invalidated credits.

(ii) The project operator must retire credits for any balance after retiring credits pursuant to 95490(h)(3)(A).

(iii) The Executive Officer may retire credits from the buffer account equivalent to remaining outstanding balance after retiring credits pursuant to 95490(h)(4)(3)(A) and (B).

(B) After 100-years post-injection:

(i) The project operator is no longer responsible to make up any credits found to be invalid due to leakage.

(ii) The Executive Officer may retire credits from the buffer account to cover any credits found to be invalid due to leakage.

(OCCIDENTAL4_FF37-19)

Comment: This would also necessitate a corresponding change to Appendix G in the protocol, i.e., revising the calculation in equation G.1 to account for those operators that choose to retain the long-tail liability. (OCCIDENTAL4_FF37-20)

Agency Response: Please see Responses M-9.1 and M-9.2 in Chapter IV regarding the 50 year project injection credit liability with risk based contribution to the buffer account. Staff did not make the suggested changes to allow the option of either 50 years of liability with 5% increase in buffer account contribution, or 100 years liability with no increase. This change would complicate recordkeeping and accounting for the buffer account. The buffer pool is a risk mechanism, and adding an option to opt into the 50-year post-injection liability requirement would weaken the buffer pool and its intended purpose.

M-6. Multiple Comments: *5 Percent Buffer Contribution*

Comment: With regard to the 5% buffer contribution:

Processes such as those shown with rapid mineralization at the CarbFix site not only show that a project can have high performance in meeting the 100 year mandate but also demonstrate that near zero risk of reversal is also possible. High performance projects should not be penalized for investments in lower performing technologies. Therefore staff should make the contributions to the buffer pool for reduced financial liability as part of the application process in which the applicants may choose the level

of financial liability they wish to take. The 15 day package eludes to performance basis with regard to the buffer account when describing verification activities.

> *" ... staff proposes that the verification team review the operator's CCS project's risk rating for determining its contribution to the LCFS Buffer Account, as calculated under Appendix G. The changes are needed to ensure that the determination made by the operator is reasonable and meets the regulatory requirements."*

USEPA regulation on carbon sequestration already allow for a performance based reduction to its 50 year mandate. The ADM Illinois Basin - Decatur Project has been granted a 40 year reduction to its post injection monitoring requirement making it just 10 years of monitoring.

Extrapolating from staffs reasoning of 1% for every 10 years of liability from the overall 100 years and extending that formulaically CARB could allow for a reduction of the financial liability down to a minimum of the EPA requirement. This would help synergize the two regulatory mandates and reduce the overall project burden on CARB staff. Additionally, as this is a performance based approach and as mentioned in the 15-day package that staff will use annual verification processes to insure that buffer contributions are adequate based on the performance of the site and its operators it should be noted that not only should buffer contributions be able to be increased if risk is evaluated higher but also decreased as well.

It should be noted that we believe that the 1% premium for 10 years is a conservative estimate and recognized that CARB required a starting point in designing this buffer pool layer. Therefore we strongly recommend that additional language be added to the protocol to allow for modifications to the percentage based on reassessed risk matrixes utilizing data submitted; this type of procedure would mirror that of insurance actuarial processes as they examine risk and insurance premiums. We believe a change such as this would promote techniques and procedures that would have the highest standards so that project operators would have the lowest "premiums". (WE3_FF22-6)

Comment: However, there remain project requirements related to buffer account contributions and post injection site care and that could impact the feasibility of projects.

The Proposed 15-day Modification requires operators to surrender between 3 and 12% of credits into the Buffer Account as insurance against potential leakage or credit invalidation and to update the risk rating every time the project goes through verification.

ARB uses a “model” to justify the proposed 5% buffer for the second half of the PISC. This assumes 20 projects (20 years injection @ 1 MT/year each = 400MT). Should one project have a complete (up to 100%) reversal, the other projects would need to have perfect containment to avoid exhausting the 5% buffer. Presumably, ARB would not permit a CO_2 storage project that was not designed for effective dispersal and trapping of CO_2 with time. After 20 years of operation and 50 years of PISC, the plume would be dispersed over a large area with a diminishing portion of free CO_2 present in thinning plume. WSPA is concerned that the “model” assumes complete failure, whereas the

plausibility of an individual or portfolio of projects suffering reversal(s) on the multi-percentage scale should be considered.

Should a far field conduit be encountered, even an open borehole, a variety of processes including relative permeability effects and pressure decline with reservoir depletion would effectively limit CO_2 loss. The actual loss would be a function of specific reservoir properties and plume / pressure state in time and space, but these factors would be constrained in the initial risk assessment required for permitting and updated with surveillance driven numerical modeling. In addition, the model used to evaluate this risk does not consider mitigation of leakage events. In the case of an actual problem, mitigation would be required and would substantially reduce the actual volume of CO_2 leaked from the formation.

A recently published paper[3] uses CO_2 flux data from natural and engineered systems, as input to predictive statistical simulations using various scenarios (e.g., density of abandoned wells, regulatory rigor). The "Storage Security Tool Calculator (SSC)" tool is available to test scenarios. The authors' main conclusion was:

> "Even when applying these conservative input parameters, results from the SSC illustrate that CO_2 storage in regions with moderate abandoned well densities and ***that are regulated using current best practice will retain 98% of the injected CO_2 over 10,000 years in more than half of cases, and result in maximum leakage of 6.3% of the injected CO_2 in fewer than 5% of cases (emphasis added)***. As expected, we find that unregulated storage is less secure. Here, however, over 10,000 years, only 22% of injected CO_2 will leak in half of cases, with the possibility that up to 33% of the injected CO_2 could leak in 5% of cases. This leakage is primarily through undetected and poorly abandoned legacy wells, and could be reduced through identification and remediation of leakage if a comprehensive site screening and monitoring program is deployed. Importantly, natural subsurface trapping mechanisms mean that this leakage will not continue indefinitely. Consequently, even with mitigation actions restricted solely to repair of abandoned wells that blow out, regions with a legacy of poorly regulated subsurface operations can reliably and robustly store and retain 78% of injected CO_2. We find that regulators can most effectively improve CO_2 storage security by identifying and monitoring abandoned wells, and perform reactive remediation should they leak."

Further, CCSP Section 2.2 (Risk Assessment) methodology does not appear to be internally consistent. Specifically, ARB will not approve projects unless there is greater than a 90% chance that the loss will be less than 1% over the project life and subsequent century. Mathematically, it is very difficult to define a risk profile for the remaining 99% of stored CO_2 that results in expected losses of 8-16% (i.e., the minimum and maximum Buffer Account rates +5% post-closure premium).

Notwithstanding these significant concerns, WSPA presents in this comment letter for ARB consideration alternatives for PISC and options for Buffer Account contributions.

Given the stage of this process, at a minimum, WSPA requests that ARB consider the following options to providing credits to the Buffer Account:

Option 1. A simple solution is to give developers the option to: contribute to the Buffer Account at the rates established through the table in Appendix G or allow for the purchase private insurance that guarantees the credit availability up to the rates assessed in Appendix G. ARB should be indifferent to holding credits in the Buffer Account compared to an insurance policy that guarantees remittance of an equivalent number of credits in the event of a reversal. If the insurance contract lapses during any verification period, the operator could be required to remit the corresponding amount of credits cumulatively due to the Buffer Account. If ARB is the named beneficiary to the insurance contract, it could hold the contract and monetize enough credits earned each year to pay the premium and maintain the policy current. Such insurance products are not yet commercially available in which case the operator could have the option to switch to an insurance scheme from the Buffer Account method when desired.

Option 2. Reduce the potential burden imposed upon the Buffer Account and therefore the level of the Buffer Account rates by first reducing the number of credits issued in the year when any leakage is detected from the total quantity of CO_2 stored during that crediting period. Only when quantities leaked exceed the total amount of CO_2 injected/stored during the current period would the state draw from the operator's Buffer Account contributions.

Option 3. Grant the operator the option to pay 5% per year into the Buffer Account or self-insure and retain the risk of 100% reversal for the final 50 years of the PISC or purchase insurance covering the risk of 100% reversal upon completion of the final risk assessment when ARB authorizes closure of injection and monitoring wells.

[3] https://www.nature.com/articles/s41467-018-04423-1

(WSPA6_FF72-2)

Agency Response: Regarding comment WE3_FF22-6 concerning the addition of language to allow for modifications to the buffer account contribution based on reassessed risk matrixes, staff maintains that the provision, as asked for by the commenter, was already present in the Protocol. The commenter asks that "staff should make the contributions to the buffer pool for reduced financial liability as part of the application process in which the applicants may choose the level of financial liability they wish to take…" This provision is already factored into the buffer account contribution calculation (see Appendix G, Table G.1), and the amount an individual project must contribute is based on financial, social, management, site, and well integrity risk. If a project operator would like to reduce their contribution to the buffer account, they need only design their project such that the risk factors are low.

Comment WE3_FF22-6 also states that, "not only should buffer contributions be able to be increased if risk is evaluated higher but also decreased as well." Again, staff has already factored this in to the buffer account calculation. Additionally, as provided in Appendix G (b) of the Protocol, operators can

recalculate their buffer account contribution at any time if one of the risk categories changes enough to change the risk rating, provided they submit a demonstration supporting the new contribution value that includes an updated storage complex/plume evolution model and a new risk assessment. Therefore, staff did not modify the Protocol in response to comment WE3_FF22-6.

Regarding comment WSPA6_FF72-2, the commenter is correct that CARB would not approve a permit a CO_2 storage project that was not designed for effective dispersal and trapping of CO_2 with time. Project evaluations and modeling exercises conducted prior to initiation of a project provide best estimates of the anticipated future performance of a project, however, actual project performance may be different as a result of inherent uncertainties in the model related to assumptions and input data. Staff determined the 5 percent buffer for the second half of the PISC based on a scenario that involves complete reversal of storage for one project. As noted by the commenter, this scenario may not be as realistic as a scenario that involves a lower level of storage reversal for several projects. However, staff's scenario is likely more conservative and will ensure, with a higher level of certainty, that the buffer account will not be exhausted if multiple projects do not perform as modeled.

Please see Response M-9.2 in Chapter IV related to the commenter's concern that there is an internal inconsistency in the Protocol's Risk Assessment methodology.

Regarding the 5% increase in buffer account contribution, please see Response M-4.2 in this chapter. Regarding the SSC tool, the results of that study are consistent with the design of the Protocol, in that a focus is put on site selection and legacy well remediation.

M-7. Multiple Comments: *General*

Comment: Carbon Engineering is currently evaluating project opportunities that involve use of atmospheric CO_2 in direct synthesis of liquid fuels, and opportunities that involve underground injection of CO_2 to generate LCFS credits or produce innovative crude. In the latter case, CE has noted hesitance on behalf of oilfield operators and market incumbents to engage in sequestration projects due to various specific measures in the CCS Protocol, most of which have been highlighted by other stakeholders[1][2].

CE encourages ARB to continue engagement with existing obligated parties, academic experts, and NGO's to resolve these concerns and create a CCS Protocol that enables efficient compliance while preserving the integrity and safety of CO_2 injection projects. Successful resolution is key to green-lighting projects like CE's that can deliver high volumes of emissions reduction and credit generation within the LCFS system.

[1] https://www.arb.ca.gov/fuels/lcfs/workshops/12042017_nrdc.pdf
[2] https://www.arb.ca.gov/fuels/lcfs/workshops/12042017_coalition.pdf

(CARBONENG1_FF34-2)

Comment: Our objectives of protecting against the loss of CO_2 to the atmosphere are shared with CARB. Therefore, we encourage CARB to adopt regulations consistent with the techniques and tools used to successfully operate CO_2 floods for EOR. These tools and techniques are proven and by using them for other purposes (i.e., assurance of leak prevention and proper quantitation), costs can be minimized making the use of geologic sequestration more economic and widespread. Should the economics of purchasing CO_2 change in the future, these tools and techniques will still be the foundation of a regulatory system that is transparent and worthy of the public's trust. (OCCIDENTAL4_FF37-1)

Comment: CIPA remains in very strong support for CARB's efforts and recognition of the benefits of Carbon Capture and Sequestration (CCS) and or Carbon Capture for Enhanced Oil Recovery (CCEOR) projects. As pointed out in CARB's Scoping Plan, liquid fuels will be a significant component of California's transportation fuel mix for decades to come. It is also known that to achieve the longer-term greenhouse gas reduction goals, that CCS and CCEOR is an important policy to pursue.

Though many changes were made to the CCS and CCEOR Protocols, CIPA still believes the requirements are not written in a way which supports CCS and CCEOR. It is critically important to ensure that the requirements associated with CCS and CCEOR are achievable and realistic such that actual projects can be developed. There are a number of remaining technical issues CIPA is aware of and that have been submitted during this rulemaking process, by a coalition of experts. CIPA requests that CARB review the proposed CCS and CCEOR protocols to ensure the requirements are not overly burdensome that would prevent CCS and CCEOR from being part of California's long-term greenhouse gas reduction methodologies.

CIPA therefore requests that CARB provide a method within the regulation to adjust the protocols, now or in the future, as the technology is applied or improved in ways that assist CCS and CCEOR project development. (CIPA2_FF43-4)

> **Agency Response:** Regarding comment CIPA2_FF43-4, staff appreciates the commenter's support of CARB's efforts and recognition of the benefits of CCS and CCEOR projects.
>
> Regarding comments CARBONENG1_FF34-2 and CIPA2_FF43-4, please see Response M-3.1 in Chapter IV describing the level of engagement with stakeholders over the last several years. Please see Response M-4.2 in this chapter, regarding technical updates to the protocol.
>
> Regarding comment OCCIDENTAL4_FF37-1, staff designed the CCS Protocol to allow for CO_2-EOR projects. Based on stakeholder feedback, staff made a number of clarifying revisions to Protocol related to CO_2-EOR. For example, please see Response M-2.1 in Chapter IV related to the term "pressure front", Response M-5.1 in Chapter IV regarding line edits related to CO2-EOR, and Response M-11 in Chapter IV related to technical recommendations for CO_2-EOR.

In response to comments OCCIDENTAL4_FF37-1 and CIPA2_FF43-4 regarding costs and ensuring Protocol requirements are not overly burdensome, staff believes the stringency level is appropriate to ensure proper site selection and site care that results in permanent sequestration as required by AB 32. Staff believes the Protocol ensures only geologically appropriate and well managed sites will be able to comply and those sites should be able to meet the requirements.

M-7.1. Multiple Comments: ***Statement of Technical Recommendations***

Comment: The modifications to the proposed protocol language will allow for projects with secure sequestration techniques that currently exist and that will be invented and deployed in the future to take advantage of the shorter timeframes in which secure CO_2 permanence can be met. This pathway to relatively short timeframes to insure 100 years of storage such as the techniques currently being deployed in the CarbFix project will incentivize more innovative technologies to be developed that can show equivalent or better performance than what currently exists today. CARB should strongly consider these modifications to the protocol language to increase the viability of the protocol and the deployment of CCS/CCUS throughout the world. (WE3_FF22-7)

Comment: We commend ARB for proposing numerous important improvements to the Protocol in the 15- Day Modifications released June 20, 2018, following the 45-day comment period on the draft Protocol. We believe that those strengthen the Protocol and afford a greater degree of oversight and environmental protection. We outline some of the most important ones below, and we support the majority of the proposed modifications. We also point out a small number of modifications that require further consideration or edits. (CATFNRDC1_FF55-1)

Agency Response: Staff appreciates the commenters' support for the Protocol. With regard to comment WE3_FF22-7, please see Response M-3 in this chapter regarding the 100-year post-injection site care requirement. Regarding comment CATFNRDC1_55-1, please also see staff's responses to comments CATFNRDC1_55-2 through CATFNRDC1_55-34 in Responses M-2.1 through M-2.4, M-4.2, M-4.3, M-8.2, M-9.5, M-11.8, M-12, and M-13 in this chapter.

M-7.2. Multiple Comments: ***Requirements for Third Party Reviewers***

Comment: Subsections (e) and (f) require the third-party reviewers of the Sequestration Site Certification and CCS Project Certification to be professional geologists or engineers, respectively, licensed under California law "or equivalent." We request that ARB clarify whether the phrase "or equivalent" is intended to allow geologists and engineers licensed in other states to meet this requirement, which is something we would support. Additionally, it is critical that third-party reviewers have specific subject matter expertise, which licensing as a professional geologist or engineer does not guarantee. An expert of choice may not be licensed in the state where the project is located, and the state need not be California. We recommend that ARB include additional qualifications beyond professional licensing to ensure that third-party

reviewers have the requisite experience to provide appropriate review. (CATFNRDC1_FF55-11)

Comment: Consistent with our comment on §§1.1.1 (e) and (f), we request that ARB clarify whether the phrase “or equivalent” in §(b)(2) is intended to allow geologists and engineers licensed in other states to meet this requirement, which we support. (CATFNRDC1_FF55-30)

> **Agency Response:** The phrase "or equivalent" in subsection C.1.1.1(e) of the Protocol was intended to an allow equivalent professional geologist from another jurisdiction to complete third-party review under the provisions of subsection C.1.1.1(b) of the Protocol. Similarly, the phrase "or equivalent" in subsection C.1.1.1(f) of the Protocol was intended to an allow equivalent professional engineer from another jurisdiction to complete third-party review under the provisions of subsection C.1.1.1(c) of the Protocol. Staff revised subsections C.1.1.1(e) and C.1.1.1(f) of the Protocol to reflect these clarifications.
>
> Staff agrees with the commenter that it is critical that third-party reviewers have specific subject matter expertise, and have revised subsections C.1.1.1(e) and C.1.1.1(f) of the Protocol to indicate that the professional geologist(s) and professional engineer(s) selected to conduct third-party reviews must be approved by the Executive Officer, to ensure they have the necessary expertise.

M-8. Multiple Comments: *Site Characterization*

M-8.1. Multiple Comments: *Open Source Code Concerns*

Comment: C.2.4.1(a)(2). The computer code utilized in the AOR delineation model must be open source and publically available to CARB and CCS Project Operators….

CO_2-EOR operators such as Occidental do not use open source computer models. Occidental purchases licenses to use proprietary commercially available models. While it is possible that an open source code may work for sequestration projects with a small number of injectors, for CO_2-EOR projects with hundreds of injectors and thousands of producers, open source codes are simply not able to process all the available data and provide meaningful results. In Occidental’s case, we purchase three licenses for software models. These models are more robust, accurate and provide results superior to those publically available models.

Occidental has explored using a subset of our data in a publically available open source code for purposes of complying with the protocol. However, we have learned that it is not feasible to take the enormous amount of data that we have collected on our operations and covert it for use in an open source code and any results we may obtain would be inferior to those from the proprietary commercially available model we are using.

We suggest that this language be revised to permit the use of a proprietary commercially available model as follows:

C.2.4.1(a)(2). The computer code utilized to model the AOR may be open source and publically available to CARB and CCS Project Operators or a validated proprietary commercially available software….

In the alternative, our CO_2-EOR modelers suggest several other solutions to ensure that CARB is comfortable with the modeling data Occidental uses, including (A) inviting CARB personnel to observe the modeling exercise, (B) having an independent third party certify the modeling results; or (C) performing and reporting on an audit of the models. (OCCIDENTAL3_FF1-4)

Comment: Section C.2.4.1(a)(2) requires the computer code utilized in the storage complex delineation to be "open source" and publically available to CARB and CCS Project Operators. To Occidental's knowledge, no such open source model exists.

Occidental's EOR modelers have looked at this provision and have spoken with representatives from the Bureau of Economic Geology at the University of Texas UT BEG and other experts in the field. These resources advise that an "open source" code that can model the complexity of our reservoir does not exist.

In preparing these comments, Occidental did conduct a literature review and is aware of several efforts to develop a reliable, verifiable and accurate open source model for sequestration. These include software available through the Matlab Reservoir Simulation Toolbox (or "MRST") and the Carbon Capture Simulation Initiative ("CCSI') led by the Office of Fossil Energy's ("FE") National Energy Technology Laboratory ("NETL"). These and similar efforts hold great promise that an open source code powerful enough to model operations and reservoirs used in enhanced oil recovery will be developed. However, the process of development could take many years if not decades and currently, each has limitations. For example:

- MRST recognizes that it "is not primarily a simulator, but is mainly intended as a toolbox for rapid prototyping and demonstration of new simulation methods and modeling concepts;"
- The CCSI code, recently released on April 2, 2018, is in its early formative stage available to researchers in "industry, government, and academia to freely use, modify, and customize in support of the development of carbon capture technologies;" and,
- Critically, for purposes of CO_2-EOR operations, no open source code can incorporate, manipulate and predict performance that is dependent on the miscibility of CO_2 in oil.

To model its operations, Occidental purchases a license to access peer reviewed commercially available proprietary models including, CMG Gem, Haliburton/Landmark VIP (Nexus), and Roxar's MORE. Each of these main-line simulators are well established, fully Peer reviewed, and competes for market shares based on the simulators accuracy and speed to solve fluid flow equations of state through complex geological models. The models Occidental uses have 20+ million lines of code and can

take several days to weeks to run each scenarios. E.g., we are currently analyzing performance of 280 wells against predicted model performance for a CO_2 flood, and the VIP/Nexus model requires 40 hours each run to complete. A typical history matched model requires hundreds of runs.

While it is possible that an open source code may work for sequestration projects with a small number of injectors, for CO_2-EOR projects with hundreds of injectors and thousands of producers, open source codes are simply not able to process all the available data and provide meaningful results. In Occidental's case, we purchase multiple licenses for the three software models mentioned. These models are more robust, accurate and provide results superior to those publically available models.

We suggest that CARB focus on what the models must be able to provide. Briefly, reliable, verifiable and accurate models that will provide the level of detail necessary for EOR to qualify for Low Carbon Fuel Standard ("LCFS") must have the following essential simulator capabilities:

a. Equation of State (EOS) driven Hydrocarbon Fluid Properties, including
    i. Miscibility Functions keyed on IFT (and Parachors)
    ii. CO_2 Solubility in Water
b. Sophisticated Three-Phase Relative Permeability, including
    i. Relative Permeability Hysteresis (for Trapped Gas)
    ii. Relative Permeability Endpoint Scaling
    iii. Choice of Three-Phase Relative Permeability Calculation Methods
c. Sophisticated Well-Bore Modeling, including
    i. Multi Segment Wellbores with capability to handle multilateral completions
    ii. Analytical Wellbore Friction Calculations for Horizontal Wells
d. Comer Point Gridding (for transmissibility calculations), including
    i. Efficient Local Grid Refinement, or Grid Coarsening
e. Fully Implicit Model Solution Formulation (Implicit Pressures and Saturations) for handling Water Alternating with Gas (WAG) with hysteresis
f. Multi-level Well Reporting and Control, including
    i. Reservoir Voidage Control with History Data - Specifying Well Histories as observed 3-phase rates, model calculates reservoir volume equivalent
    ii. Reporting Production and Injection as User Defined Gatherings Centers, or Groups (including groups of groups, overlapping groups, or total field)
    iii. For Prediction, Injection Rates (by Group) calculated from reservoir production (Voidage)
g. Visualization of Results, including:

i. 30 Visualization Tool for all Simulation Properties (Static and Dynamic) as a Function of Time, including relative position of wellbores

ii. Efficient Well and Gathering Center Performance Plotting

We suggest that this language be revised to permit the use of a proprietary commercially available model as follows:

Section C.2.4.1(a)(2). The computer code(s) utilized in the storage complex delineation model and plume extent modeling must be (1) validated for use in peer reviewed literature; and, either (2) open source and publically available to CARB and CCS Project Operators; or (3) a validated commercially available software. (OCCIDENTAL4_FF37-3)

Agency Response: Please see Response M-12.1. in Chapter IV.

Based on these comments, staff better understands the limitations associated with existing open source computational modeling software. In response to these comments, staff modified the requirements of subsection C.2.4.1(a)(2)(A) to allow for the use of proprietary software provided the "code(s) utilized in the storage complex delineation and plume extent modeling [are] 1. validated for use in peer-reviewed literature; 2. available to CARB and CCS Project Operators during CARB's review of any permanence certification application, and preferably open source; and 3. validated by a third party approved by the Executive Officer and applicant."

M-8.2. Multiple Comments: ***Concerns with Formation Testing and Well Logging Plan Requirements***

Comment: C.2.3.1(a). A CCS Project Operator must submit a Formation Testing and Well Logging Plan with the Sequestration Site Certification. The plan must demonstrate to the Executive Officer how the CCS Project Operator will collect geologic and hydrogeologic data required to show the selected storage complex is suitable for receiving and containing CO_2.

This and other requirements in this section appear to apply to new projects. Occidental will be submitting a Sequestration Site Certification for one or more of its existing CO_2-EOR projects. In lieu of a formation testing and well logging plan that meets each of the specific provisions in the Protocol, Occidental can provide decades of data describing the sequestration zone and storage complex in detail. We read the language in this section and others as providing guidance, e.g., C.2.3.1(b) states that "[t]his section provides guidance on the formation testing and well logging activities that a CCS Project Operator must conduct...." This suggests that there should be flexibility in the information that a project applicant is required to submit for a particular CCS Project. E.g., in a CO_2-EOR field, continuous monitoring data can demonstrate with greater certainty that a storage complex is suitable for receiving and containing CO_2 and a plan to collect geologic and hydrogeologic data may not be needed.

We suggest this alternate language that recognizes that the Executive Officer should have and exercise an appropriate level of discretion for existing projects:

C.2.3.1(b). This section provides guidance on the formation testing and well logging activities that the CCS Project Operator must conduct to generate the information and data required to confirm that the storage complex is able to meet the permanence requirements for carbon sequestration, as required in subsection C.1.1.2. For CO_2-EOR the information required may vary where the Executive Officer determines that historical data provides an equivalent demonstration that the selected storage complex is suitable for receiving and containing CO_2. (OCCIDENTAL3_FF1-2)

Comment: Section C.2.3.1 requires a formation testing and well logging program. Generally, CO_2-EOR operations have already conducted formation testing and well logging. It appears that C.2.3.1(b) attempts to recognize that C.2.3.1(e) through C.2.3.1(i) shall apply to any new wells, not to current wells. Occidental supports such an interpretation as it may prove difficult to impossible to produce data for all wells in a CO_2-EOR operation occurring at a field that has been in operation for decades. We do believe that the formation testing and well logging program elements are critical to demonstrating permanence and operators should be required to provide a certification to CARB that its existing wells are performing properly. Accordingly, Occidental requests that this interpretation be recognized in the rule making package. (OCCIDENTAL4_FF37-2)

> **Agency Response:** Please see Response M-12.6. in Chapter IV. Staff notes that this response also applies to existing CO_2-EOR projects that may be proposed as CCS projects.

M-8.3. Multiple Comments: ***Concerns with AOR Evaluation Language***

Comment: C.2.4.1(a)(1)(A). The CCS Project Operator must delineate the AOR using a computational model that, among other things, predicts the lateral and vertical migration of the free-phase CO_2 plume and pressure front, as well as the dissolved CO_2 plume and formation fluids in the subsurface....

A CO_2-EOR project simply does not feature a pressure front. Rather the field pressure is stabilized. This is a critical difference between an existing CO_2-EOR project that stabilizes pressure in the zone to maximize enhanced oil recovery, and a sequestration project that pressurizes a reservoir through continuous injection. Consequently, predictions of the CO_2 pressure front should not be required.

We suggest the following additional language be inserted that recognizes this difference:

C.2.4.1.(a)(1)(A). For CO_2-EOR projects, the computational model must predict the movement of CO_2 in the subsurface…. (OCCIDENTAL3_FF1-3)

Comment: C.2.4.4(c)(1). CCS Project Operators must update and verify the site model and re-evaluate the size and shape of the AOR when…material changes have

occurred such that the actual CO_2 free-phase plume or pressure front extend beyond the area originally modeled….

As described above, a CO_2-EOR project simply does not feature a pressure front. Rather the field pressure is stabilized. This is a critical difference between an existing CO_2-EOR project that stabilizes pressure in the zone to maximize enhanced oil recovery and a sequestration project that pressurizes a reservoir through continuous injection.

We suggest the following additional language be inserted that recognizes this difference:

C.2.4.4(c)(1). CCS Project Operators must update and verify the site model and re-evaluate the size and shape of the AOR when…material changes have occurred that significantly alter the predicted or measured subsurface movement of CO_2 within the sequestration zone. (OCCIDENTAL3_FF1-5)

Comment: C.2.4.4.1(c)(1). Triggers for an unscheduled AOR reevaluation include observed migration of the plume in any direction that is faster than predicted by the model…..

Occidental recognizes that an AOR reevaluation may be appropriate in certain circumstances. However, the use of the phrase "faster than predicted" is imprecise. CO_2 in a CO_2-EOR project may move at varying velocities based on operating conditions that may change. We suggest the following revision:

C.2.4.4.1(c)(1). Triggers for an unscheduled AOR reevaluation include indications that the subsurface CO_2 movement, observed from injection and, in the case of CO_2-EOR, production behavior, is migrating beyond the acceptable range predicted by the model.

Similarly, C.2.4.4.1(c)(2) states, triggers for an unscheduled AOR reevaluation include observed thickness of the CO_2 plume that is much thinner than that predicted by the model. For CO_2-EOR CO_2 plume thickness is not a meaningful measure because oil and CO_2 have the same resistivity index and the low permeability of the formation renders seismic data of limited utility. We can and do make adjustments to ensure CO_2 is being injected and maintained in the targeted reservoir as predicted by simulation models. We understand CARB's intent as requiring a revaluation when there is some indication that subsurface conditions are not as expected or predicted. We suggest the following wording to account for variations between different formations that might be used for CO_2 sequestration:

C.2.4.4.1(c)(2). Triggers for an unscheduled AOR reevaluation include indications that the subsurface CO_2 movement, observed from injection and, in the case of CO_2-EOR, production behavior, is not consistent with model predictions and suggests movement of CO_2 outside of the intended formation. (OCCIDENTAL3_FF1-6)

> **Agency Response:** Regarding comments OCCIDENTAL3_FF1-3 and OCCIDENTAL3_FF1-5, please see Response M-2.1 in Chapter IV related to the

use of "elevated pressure" instead of "pressure front." The terminology change addresses the technical concern raised by the commenter.

Regarding comment OCCIDENTAL3_FF1-6, staff agrees that the use of the phrase “faster than predicted” is imprecise and may cause uncertainty in determining when a reevaluation of the CO_2 plume extent is needed. Staff revised subsection C.2.4.4(c)(1) of the Protocol to require the operator to perform a CO_2 plume extent evaluation if there is observed migration of the CO_2 plume beyond the acceptable range predicted by the computational model. Staff also agrees that for CO_2-EOR, CO_2 plume thickness is not a meaningful measure because oil and CO_2 have the same resistivity index and the low permeability of the formation renders seismic data of limited utility. Staff revised subsection C.2.4.4(c)(2) of the Protocol to require a CO_2 plume extent evaluation if the observed shape of the CO_2 plume is not consistent with model predictions, suggesting potential movement of CO_2 outside of the intended formation.

M-8.4. ***Concerns with Modelling Language***

Comment: Section 2.4.2 (c). Requires a single modeling exercise for all wells within a single CCS project.

Occidental provided detailed and extensive comments to the computer modeling provision above. In addition, the complexity of a given reservoir and operation may necessitate multiple modeling exercises. The critical questions are whether the model provides reliable, verifiable and accurate results. If multiple modeling exercises provide better results, there should be no prohibition on conducting such an exercise.

We suggest deleting 2.4.2(c) in its entirety or revising the language as follows:

(c) A single AOR modeling exercise may be conducted for all wells within a single CCS project. (OCCIDENTAL4_FF37-10)

Agency Response: As noted in comment GCCC1_14-76 in Response M-5.1. in Chapter IV, individual wells will impact the plume shape and pressure evolution. In order to obtain the most accurate, reliable, and verifiable estimate of the overall plume shape and pressure evolution for the entire project, all wells must be included in a single model run. Therefore, staff did not revise subsection C.2.4.2(c) of the Protocol to incorporate the commenter’s proposed revisions.

M-8.5. Multiple Comments: ***Description of “All” Geologic Structures***

Comment: C.2.3(c)(6). A CCS Project Operator must submit (along with other information) "a full description of all geologic structure, including faults and fractures, which intersect the storage complex and all data relevant to the transmissivity of these features…including (A) the location, depth, displacement, and geometry of the fault or fracture...(C)...a full geometric description in support of...."

A description of the geologic structure is essential to assessing the risk of a storage complex. We understand the intent of this provision is to capture structures, including faults and fractures, that might provide leakage pathways. However, a full description of all structures may not be possible because not all subsurface structures are known or measureable. The majority are fine hairline cracks of limited length that do not pose a risk of leakage. To recognize that all faults and fractures are not identifiable or a risk, we suggest this alternate language:

C.2.3(c)(6). "A description of known geologic structures, including all significant faults and fractures, which intersect the storage complex and all available data relevant to assessing the transmissivity of these features…including (A) the location, depth, displacement, and geometry of the faults or fractures that can be mapped...(C) a sufficient description in support of...." (OCCIDENTAL3_FF1-1)

Comment: We support the intent behind the proposed change to subsection (b)(6) but the term "significant" is vague and undefined. We propose instead that operators be required to identify and describe all geologic structures that are "material to leakage" or, alternatively, "material to permanence." (CATFNRDC1_FF55-12)

> **Agency Response:** Regarding comment OCCIDENTAL3_FF1-1, please see Response M-12.2 in Chapter IV.
>
> Regarding comment CATFNRDC1_FF55-12, staff reviewed the commenter's proposed revision to the description of geologic features in subsection C.2.3(a)(6) of the Protocol and found that this proposed revision (i.e., addition of "material to leakage" or alternatively, "material to permanence") does not provide any more clarity than staff's revision to the description (i.e., "significant"), when taken in the context of subsection C.2.3(a)(6). Therefore, staff did not further revise subsection C.2.3(a)(6) to include the commenter's proposed description.

M-9. Multiple Comments: *Well Construction and Operating Requirements*

M-9.1. Multiple Comments: *Well Materials*

Comment: C.3.1(c)(1). All well materials must be compatible with the fluids with which the materials may be expected to come into contact with and must meet or exceed standards developed for such materials by API, ASTM or comparable standards acceptable to the Executive Officer.

All well materials must be selected and formulated to minimize corrosion caused by fluids that the materials may be expected to contact. Tubular well components must meet or exceed standards developed for such materials by API, ASTM or comparable standards acceptable to the Executive Officer – e.g. corrosion inhibitors may be added to wells in a CO_2-EOR project to retard corrosion as well as using CO_2 resistant coatings on injection well tubulars. Annular sealant materials between wellbore and tubular components must be corrosion resistant to CO_2 and formation fluids within the sequestration zone. We believe the aforementioned measures satisfy the intent of this provision but suggest the following revision to the language for clarification:

C.3.1(c)(1). "All well materials must be constructed to minimize corrosion caused by the fluids with which the materials may be expected to come into contact with and must meet or exceed standards developed for such materials by API, ASTM or comparable standards acceptable to the EO. E.g., corrosion inhibitors may be added to wells in a CO_2-EOR project to retard corrosion."

Similarly, C.3.1(c)(5) states that cement and cement additives must be compatible with the CO_2 stream and formation fluids within the sequestration zone. We suggest the following revision:

C.3.1(c)(5). "Cement and cement additives must be corrosion resistant to the CO_2 stream and formation fluids within the sequestration zone." (OCCIDENTAL3_FF1-7)

Comment: C.3.1 (c)(1). All well materials must be compatible with the fluids with which the materials may be expected to come into contact with and must meet or exceed standards developed for such materials by API, ASTM or comparable standards acceptable to the Executive Officer.

All well materials must be selected and formulated to minimize corrosion caused by fluids that the materials may be expected to contact. Tubular well components must meet or exceed standards developed for such materials by API, ASTM or comparable standards acceptable to the Executive Officer - e.g. corrosion inhibitors may be added to wells in a CO_2-EOR project to retard corrosion as well as using CO_2 resistant coatings on injection well tubulars. Annular sealant materials between wellbore and tubular components must be corrosion resistant to CO_2 and formation fluids within the sequestration zone. We believe the aforementioned measures satisfy the intent of this provision but suggest the following revision to the language for clarification:

C.3.1(c)(1). "All well materials must be constructed to minimize corrosion caused by the fluids with which the materials may be expected to come into contact with and must meet or exceed standards developed for such materials by API, ASTM or comparable standards acceptable to the Executive Officer. E.g., corrosion inhibitors may be added to wells in a CO_2-EOR project to retard corrosion."

Similarly, C.3.1(c)(5) states that cement and cement additives must be compatible with the CO_2 stream and formation fluids within the sequestration zone. We suggest the following revision:

C.3.1(c)(5). "Cement and cement additives must be corrosion resistant to the CO_2 stream and formation fluids within the sequestration zone." (OCCIDENTAL4_FF37-11)

> **Agency Response:** Staff agrees with the commenter that all well materials must be constructed to minimize corrosion caused by fluids with which the materials may be expected to come into contact. Staff also agrees with the commenter that cement and cement additives must be corrosion resistant to the CO_2 stream and formation fluids within the sequestration zone. Staff determined that existing language in subsections C.3.1(c)(1) and C.3.1(c)(5) of the Protocol is sufficient. For clarity, staff added examples of well materials that must be compatible with

the CO_2 stream and other fluids that may come in contact with the well materials to subsections C.3.1(c)(1) and C.3.1(c)(5).

M-9.2. ***Surface Casing Requirements***

Comment: C.3.1(c)(2) requires that surface casing must extend through the base of the lowermost freshwater aquifer and be cemented to the surface through the use of a single or multiple strings of casing and cement.

Occidental extends the surface casing of its injection wells to the surface. Depending on their age, active production wells may not be cemented to the surface. The nature and use of a production well is very different from an injector. A production well is essentially a pathway out of the reservoir. Oil, produced water and gas, that may include entrained CO_2, is extracted through production wells. Each of these products are captured at the surface and separated. Oil and natural gas is captured for sale. Virtually all of the CO_2 (except for a very small percentage of CO_2 lost as fugitive emissions) and a percentage of the produced water is captured and recycled for reuse. Consequently, the surface casing of production wells do not necessarily need to extend to the surface. It would be extremely expensive with no corresponding enhancement in performance for a CO_2-EOR operator to rework or plug and abandon structurally sound, properly functioning, and sound production wells.

Occidental suggests that compliance with sections C.2.4.3(b), (c) and (d), which require an assessment of wells that penetrate the storage complex and require corrective action, provides the storage complex with the requisite level of protection from leaks. In addition, the protocol's calculation methodology already ensure that a project operator will not generate LCFS credits for CO_2 lost due to fugitive emissions, entrained CO_2 or other leakage.

We suggest the following revision:

C.3.1(c)(2) "Surface casing of all injection wells must extend through the base of the lowermost freshwater aquifer and be cemented to the surface through the use of a single or multiple strings of casing and cement. Production wells must be assessed pursuant to C.2.4.3 and, if necessary, take any required corrective action." (OCCIDENTAL4_FF37-12)

Agency Response: As indicated by the commenter, a production well is essentially a leakage pathway out of the reservoir for oil, produced water, and gas, including entrained CO_2. If surface casing and cementing does not extend all the way to the surface, there is the potential for leakage of oil and produced water and gas, including CO_2 out of the production well above the point where surface casing ends. For this reason, staff did not revise subsection C.3.1(c)(2) of the Protocol as suggested by the commenter.

M-9.3. Multiple Comments: *Timing of Pre-Injection Testing*

Comment: C.3.2(a)(1). During drilling and construction of wells, the CCS Project Operator must…determine or verify permeability and porosity….

In CO_2-EOR we do not test during drilling because of the presence of drilling fluids in the well. We wait until the well has stabilized after drilling. Otherwise, drilling mud and other residues would compromise the results. We suggest revising the language as follows to clarify that in CO_2-EOR projects, testing occurs after drilling and is part of the construction of a well:

C.3.2(a)(1). "When drilling and constructing wells, the CCS Project Operator must…determine or verify permeability and porosity…." (OCCIDENTAL3_FF1-8)

Comment: C.3.2(a)(1). "During drilling and construction of wells, the CCS Project Operator must... determine or verify permeability and porosity...."

In CO_2-EOR we do not test during drilling because of the presence of drilling fluids in the well. We wait until the well has stabilized after drilling. Otherwise, drilling mud and other residues would compromise the results. We suggest revising the language as follows to clarify that in CO_2-EOR projects, testing occurs after drilling and is part of the construction of a well:

C.3.2(a)(1). "When drilling and constructing wells, the CCS Project Operator must... determine or verify permeability and porosity...." (OCCIDENTAL4_FF37-11a)

> **Agency Response:** Staff agrees with the commenter's suggested revisions which clarify that in CO_2-EOR projects, testing occurs both during and after drilling and well construction. Staff revised subsection C.3.2(a)(1) of the Protocol as suggested.

M-9.4. Multiple Comments: *Enlargement of a Pilot Hole*

Comment: C.3.2(c)(1). The CCS Project Operator must submit…a descriptive report that includes interpretation of the results of…(1) Deviation checks during drilling on all holes constructed by drilling a pilot hole that is enlarged by reaming or other method.

We have had Occidental's drilling and completion specialists examine this provision and it is not clear what is required or what CARB intends. Occidental personnel advise that at no point would we drill a pilot hole that is enlarged by reaming or other method. We request that CARB review this provision and provide clarification as to its intent and application. (OCCIDENTAL3_FF1-9)

Comment: C.3.2(c)(1). "The CCS Project Operator must submit...a descriptive report that includes interpretation of the results of...(1) Deviation checks during drilling on all holes constructed by drilling a pilot hole that is enlarged by reaming or other method."

We have had Occidental's drilling and completion specialists examine this provision and it is not clear what is required or what CARB intends. Occidental personnel advise that at no point would we drill a pilot hole that is enlarged by reaming or other method. We request that CARB review this provision and provide clarification as to its intent and application. (OCCIDENTAL4_FF37-11b)

> **Agency Response:** As indicated in subsection C.3.2(c)(1) of the Protocol, the intent of this provision is to ensure that vertical avenues for fluid movement in the form of diverging holes (from the pilot hole) are not created during enlarging of a pilot hole. This provision would apply only in cases where CCS Project Operators drill pilot holes and subsequently enlarge the pilot holes by reaming or another method. Staff revised subsection C.3.2(c)(1) of the Protocol to clarify.

M-9.5. Multiple Comments: ***Injection Pressure***

Comment: C.3.3(b). The CCS Project Operator must ensure that injection pressure does not exceed 80 percent of the fracture/parting pressure of the sequestration zone so as to ensure that injection does not initiate or propagate existing fractures….

Occidental recognizes the need to prevent injection pressures from exceeding the fracture/parting pressure. An understanding of the fracture/parting pressure is critical to Occidental's business, maximizing oil recovery, avoiding the propagation or initiation of any existing fractures, and safeguarding against the loss of CO_2. In Occidental's case, we use a SCADA control system architecture to continuously monitor subsurface conditions to ensure, among other things, that fracturing/parting pressures are not exceeded. Occidental CO_2-EOR projects inject at pressures 50 psi below fracture/parting pressure. Depending on the reservoir, this may be greater than 80% of the fracture/parting pressure. We suggest the following revised language to recognize CO_2-EOR operating conditions:

C.3.3(b). "The CCS Project Operator must ensure that injection pressure is continuously monitored and for CO_2-EOR Project Operators is at least 50 psi below fracture/parting pressure."

Similarly, C.4.3.1.3(c) states that the CCS Project Operator must ensure that the injection pressure remains at or below 80 percent of the fracture pressure of the sequestration zone. We suggest the following revised language:

C.4.3.1.3(c). "The CCS Project Operator must ensure that injection pressure is continuously monitored and for CO_2-EOR Project Operators is at least 50 psi below fracture/parting pressure." (OCCIDENTAL3_FF1-10)

Comment: Sections C.3.3(b) and C.4.3.1.3(c) require that a CCS Project Operator ensure that injection pressure does not exceed 80% of the fracture/parting pressure of the sequestration zone.

Companies that sequester CO_2 incidental to enhanced oil recovery (EOR) must balance the need to inject CO_2 at a pressure above minimum miscibility pressure (MMP) to

optimize oil production, and to maintain injection below the fracture/parting pressure of the reservoir. Injection pressure that exceeds fracture/parting pressure or less than required to maintain MMP will result in oil accelerated production decline. The operator of a mature EOR project manages this balance by maintaining an injection to withdrawal ratio of or near one. Once an optimum reservoir pressure for injection and production is achieved, an EOR reservoir pressure does not increase overtime. In many instances, the required injection pressure of 80% below frac pressure may result in reservoir pressure drop to below MMP and/or an inability to continue injection due to injection pressure being less than existing reservoir pressure.

To ensure that it injects below fracture/parting pressure and above field pressure, Occidental uses a SCADA (Supervisory Control and Data Acquisition) system that collects data from sensors at each well and other locations and sends this data to a central computer system that manages and controls the data and processes in real time. Although there is some minor variations possible, through its 40+ years of CO_2-EOR experience, Occidental recommends using an optimum injection pressure that is at least 50 psi below fracture/parting pressure. Occidental has determined that this is sufficiently below the fracture/parting pressure to protect the reservoir while optimizing production. Further, this is a more precise limit that will prove easier to implement, measure, monitor and report. Occidental has included a detailed description of its SCADA system in Attachment B.

Consequently, the Protocol's proposed language limiting injection pressure to 80% of the fracture/parting pressure is not necessary given the degree of control an operator of an enhanced oil recovery operation should exercise and will preclude any CO_2-EOR from qualifying under the CARB protocol for generation of LCFS credits.

Occidental acknowledges that until a new sequestration project develops a full understanding of its reservoir, an 80% limitation may be appropriate to safeguard a reservoir's cap rock. However, such a limitation is not necessary where a CO_2-EOR operation has 40 years or more of operational data demonstrating performance. To retain such a provision will preclude a CO_2-EOR project from qualifying under this protocol.

Occidental suggests that the protocol's language in sections 3.3(b) and 4.3.l.3(c) be revised as follows:

C.3.3(b) The CCS Project Operator must ensure that injection pressure is continuously monitored and:

(1) For a CO_2-EOR Project, is maintained such that there is a minimum differential of 50 psi between the operating pressure in the reservoir and the fracture/parting pressure.

(2) For all other CCS Projects, does not exceed 80 percent of the fracture/parting pressure of the sequestration zone so as to ensure that injection does not initiate or propagate existing fractures in the sequestration zone.

(3) In no case may injection pressure initiate fractures in the confining system, cause movement of the injection or formation fluids out of the storage complex, or unacceptably increase risk of significant induced seismicity.

It appears that Section 4.3.1.3(c) is redundant and not necessary. However, should CARB prefer to retain this provision because it merits repeating in the section on Continuous Monitoring of Injection Pressure, we suggest ensuring that both protocol provisions are identical:

C.4.3.1.3(c) The CCS Project Operator must ensure that injection pressure is continuously monitored and:

(1) For a CO_2-EOR Project, is no greater than 50 psi below fracture/parting pressure.

(2) For all other CCS Projects, does not exceed 80 percent of the fracture/parting pressure of the sequestration zone so as to ensure that injection does not initiate or propagate existing fractures in the sequestration zone.

(3) In no case may injection pressure initiate fractures in the confining system, cause movement of the injection or formation fluids out of the storage complex, or unacceptably increase risk of significant induced seismicity.

(OCCIDENTAL4_FF37-4)

Agency Response: Based on the commenter's extensive experience in using injection pressures that may be above 80 percent of the fracture/parting pressure of the sequestration zone for CO_2-EOR, staff revised subsection C.4.3.1.3(c) of the Protocol to allow use of an alternative injection pressure limit, subject to Executive Officer approval. Please see Response M-16 in Chapter IV. Staff also revised subsection C.4.3.1.3(c) to be consistent with subsection C.3.3(b).

M-9.6. Multiple Comments: ***Injection Well Shutdowns***

Comment: C.3.3(f)(1). If a shutdown is triggered or a loss of mechanical integrity is discovered, the CCS Project Operator must (1) immediately cease injection, otherwise all credits generated are subject to invalidation; …(3) notify the Executive Officer in writing within 24 hours….

CO_2-EOR projects have much in common with other industrial processes. Like industrial processes, computer control systems may alarm from time to time for minor issues and operator intervention is required to check and reset the system. Occidental utilizes a SCADA control system to monitor its CO_2-EOR operations. The system is designed to continuously monitor conditions within the EOR operation. Events beyond Occidental's control and that do not reflect a downhole upset condition may occur that could trigger a shutdown. E.g., inclement weather that may cause a temporary interruption of power, voltage spikes, an unexpected failure of a monitoring probe or wiring despite proper and timely checks and maintenance. In many of these cases, the SCADA will trigger an alarm and may shutdown injection until the situation can be checked and repairs, if needed, initiated. None of these events risk a loss of CO_2 from

the reservoir and we don't believe that it is CARB's intent to have the protocol require 24-hour written notice for all events. Rather, we understand that CARB seeks to have notice of significant events. We suggest that minor events of the nature describe above should be reported quarterly or annually. Accordingly, Occidental agrees that major event, e.g., a system failure accompanied by a loss of sequestered CO_2 from the reservoir should trigger notice to the Executive Officer. To recognize these scenarios, we suggest the following revisions:

C.3.3(f)(1). "If an un-remedied shutdown is triggered or a loss of mechanical integrity is discovered with an accompanying loss of CO_2 from the sequestration zone that results in an invalidation of LCFS credits, the CCS Project Operator must (1) immediately cease injection, otherwise all credits generated are subject to invalidation[1]; …(3) notify the Executive Officer in writing within 24 hours…."

Similarly, C.3.4(a) states that the CCS Project Operator must cease injection into the affected injection well and must not resume injection…without Executive Officer subsequent approval if (1) MI testing has not been performed as required; (2) the well fails MI; (3) an automatic alarm is triggered….

Again, an automatic alarm could be triggered by a relatively benign process condition or other conditions like inclement weather. We do not understand CARB's intent as requiring Executive Officer approval to restart injection after a CO_2-EOR operator responds to and corrects a false alarm or other relatively benign and corrected operating condition. We suggest the following revisions:

C.3.4(a). "The CCS Project Operator must cease injection into the affected injection well and must not resume injection…without EO subsequent approval if (1) MI testing has not been performed as required; (2) an un-remedied automatic alarm is triggered with an accompanying loss of sequestered CO_2 that results in an invalidation of LCFS credits, …."

[1] Although the suggested revision retains the term "invalidation", Occidental submitted comments related to this on April 23, 2018. The comments on page 15 of the attached link should be considered simultaneously with the suggested revisions. https://www.arb.ca.gov/lists/com-attach/123-lcfs18-BmpWMwZhU3NVDFc0.pdf

(OCCIDENTAL3_FF1-11)

Comment: Sections C.3.3(f)(1) provides that if a shutdown is triggered or a loss of mechanical integrity is discovered, the CCS Project Operator must (1) immediately cease injection, otherwise all credits generated are subject to invalidation; ...(3) notify the Executive Officer in writing within 24 hours....

CO_2-EOR projects have much in common with other industrial processes. Like industrial processes, computer control systems may alarm from time to time for minor issues and operator intervention is required to check and reset the system. Occidental utilizes a SCADA control system to monitor its CO_2-EOR operations. The system is designed to continuously monitor conditions within the EOR operation. Events beyond Occidental's control and that do not reflect a downhole upset condition may occur that could trigger a shutdown. E.g., inclement weather that may cause a temporary interruption of power, voltage spikes, an unexpected failure of a monitoring probe or

wiring despite proper and timely checks and maintenance. In many of these cases, the SCADA will trigger an alarm and may shutdown injection until the situation can be checked and repairs, if needed, initiated. None of these events risk a loss of CO_2 from the reservoir and we don't believe that it is CARB's intent to have the protocol require 24-hour written notice for all events. Rather, we understand that CARB seeks to have notice of significant events. We suggest that minor events of the nature describe above should be reported quarterly or annually. Accordingly, Occidental agrees that major event, e.g., a system failure accompanied by a loss of sequestered CO_2 from the reservoir should trigger notice to the Executive Officer.

To recognize these scenarios, we suggest the following revisions:

C.3.3(f)(1). "If an un-remedied shutdown is triggered or a loss of mechanical integrity is discovered with an accompanying loss of CO_2 from the sequestration zone that results in an invalidation of LCFS credits, the CCS Project Operator must (1) immediately cease injection, otherwise all credits generated are subject to invalidation[1]; …(3) notify the Executive Officer in writing within 24 hours...."

Similarly, C.3.4(a) states that the CCS Project Operator must cease injection into the affected injection well and must not resume injection...without Executive Officer subsequent approval if (1) MI testing has not been performed as required; (2) the well fails MI; (3) an automatic alarm is triggered....

Again, an automatic alarm could be triggered by a relatively benign process condition or other conditions like inclement weather. We do not understand CARB's intent as requiring Executive Officer approval to restart injection after a CO_2-EOR operator responds to and corrects a false alarm or other relatively benign and corrected operating condition. We suggest the following revisions:

C.3.4(a). "The CCS Project Operator must cease injection into the affected injection well and must not resume injection...without EO subsequent approval if (1) MI testing has not been performed as required; (2) an un-remedied automatic alarm is triggered with an accompanying loss of sequestered CO_2 that results in an invalidation of LCFS credits,...."

[1] Although the suggested revision retains the term "invalidation", Occidental submitted comments related to this on April 23, 2018. The comments on page 15 of the attached link should be considered simultaneously with the suggested revisions. https://www .arb.cu.!mv/lisl<.,/com-attach/ 123-lcl's 18-BmpWMwZhU3NVDFcO.pdf

(OCCIDENTAL4_FF37-5)

Agency Response: It is not CARB's intent to require notification of the Executive Officer within 24 hours of minor shutdown events. As indicated in subsection C.3.3(f) of the Protocol, this notification is required only if upon immediate investigation of the shutdown, the well appears to be lacking mechanical integrity, or if monitoring required under subsection C.3.3(e) of the Protocol otherwise indicates that the well may be lacking mechanical integrity. To clarify this requirement in response to these comments, staff revised subsection C.3.3(f) to indicate that the provisions in subsections C.3.3(f)(1) through C.3.3(f)(5) would apply only if an un-remedied shutdown is triggered or a

loss of mechanical integrity is discovered, and if upon immediate investigation of the shutdown, the well appears to be lacking mechanical integrity, or if monitoring required under subsection C.3.3(e) of the Protocol otherwise indicates that the well may be lacking mechanical integrity.

Similarly, in subsection C.3.4(a) of the Protocol, it is not CARB's intent to require cessation of injection and Executive Officer approval to resume injection into the well for all automatic alarm or automatic shut-off system events in order to receive LCFS credits. To clarify, staff revised subsection C.3.4(a)(3) of the Protocol to indicate that this provision would apply only when an un-remedied automatic alarm or automatic shut-off system is triggered.

M-10. Multiple Comments: *Operational Monitoring Requirements*

M-10.1. Multiple Comments: *Annulus Fluid Volume*

Comment: C.4.1(a)(2). Testing and monitoring associated with CCS projects must include…(2) installation and use…of continuous recording devices to monitor…(3) the annulus fluid volume added….

In CO_2-EOR operations, we monitor the annulus pressure rather than the annulus fluid level. We suggest the following revision to recognize this well requirement:

C.4.1(a)(2). Testing and monitoring associated with CCS projects must include…(2) installation and use…of continuous recording devices to monitor…(3) annulus fluid volume, if present…. (OCCIDENTAL3_FF1-12)

Comment: C.4.1(a)(2). Testing and monitoring associated with CCS projects must include ... (2) installation and use ... of continuous recording devices to monitor. .. (3) the annulus fluid volume added ....

In CO_2-EOR operations, we monitor the annulus pressure. We do not maintain fluid in the annulus. We suggest the following revision to recognize this well requirement:

C.4.l(a)(2). Testing and monitoring associated with CCS projects must include ... (2) installation and use ... of continuous recording devices to monitor ... (3) annulus fluid volume, if present. ... (OCCIDENTAL4_FF37-14)

Agency Response: Subsection C.3.3(d) of the Protocol requires that the operator fill the annulus between the tubing and the long string casing with a non-corrosive fluid. Therefore, staff does not agree that the clarification suggested by the commenter is necessary as there would be no case in which annulus fluid is not present.

M-10.2. *Free-Phase CO_2 Plume and Pressure Front Monitoring Requirements*

Comment: C.4.3.2.1. CCS Project Operators are required to track the extent of the free-phase CO_2 plume, and the pressure development (e.g., the pressure front) by

using: (1) Direct methods in the sequestration zone, and (2) Indirect methods such as seismic, electrical…downhole CO_2 detection tools….

As described above, a CO_2-EOR project simply does not feature a pressure front. Rather the field pressure is stabilized. This is a critical difference between an existing CO_2-EOR project that stabilizes pressure in the zone to maximize enhanced oil recovery and a sequestration project that pressurizes a reservoir through continuous injection. We suggest the following revisions:

C.4.3.2.1. CCS Project Operators are required to track the extent of the free-phase CO_2 plume, and the pressure development (e.g., the pressure front) by using: (1) Direct methods in the sequestration zone, and (2) Indirect methods such as seismic, electrical…downhole CO_2 detection tools… CO_2-EOR Project Operators are required to continuously monitor the subsurface movement of CO_2 by using: (1) Direct methods in the sequestration zone, and (2) Indirect methods such as seismic, electrical…downhole CO_2 detection tools…. (OCCIDENTAL3_FF1-13)

> **Agency Response:** Please see staff's response to comment CATF1_100-4a in Response M-2.1 in Chapter IV related to the relevance of the term "pressure front" in CO_2-EOR.

M-10.3. Multiple Comments: *Seismic Monitoring Requirements*

Comment: C.4.3.2.3 (a). The CCS Project Operator must deploy and maintain a permanent, downhole seismic monitoring system….

Because CO_2-EOR projects stabilize the reservoir field pressure to enhance oil recovery, there is no risk of over-pressurization and no risk of seismic activity associated with CO_2-EOR. As a result, Occidental does not deploy a seismic array consisting of a permanent, downhole seismic monitoring system. Occidental does monitor TexNet, a system installed by the University of Texas at Austin's Bureau of Economic Geology. We suggest the following revision:

C.4.3.2.3. The CCS Project Operator must deploy and maintain a permanent, downhole seismic monitoring system….A CO_2-EOR Project Operator may choose to monitor seismic activity consistent with C.4.3.2.3(b). (OCCIDENTAL3_FF1-14)

Comment: C.4.3.2.3 requires the CCS Project Operator to deploy and maintain a permanent, downhole seismic monitoring system to determine the presence or absence of any induced microseismicity events.

Occidental, the oil and gas industry and states with oil and gas producing regions recognize the importance of understanding, monitoring and reporting seismicity events that may be induced through human activities.

Occidental belongs to and is a funder of the University of Texas CISR consortium (Center for Integrated Seismicity Research or CISR) which manages the TexNet monitoring system. Occidental is a member of CISR Science Advisory Committee. The

goal of this committee is to " ... provide a robust mechanism for dialog, guidance, and exchange of technical advice ... " for TexNet.

TexNet has two primary goals: (1) to monitor, locate, and catalog seismic activity with magnitudes of M 2.0 and larger, and (2) to improve the state's ability to rapidly investigate ongoing earthquake sequences in Texas. The system operates 17 permanent systems with an additional 22 planned and maintains numerous portable unites to monitor, locate, and catalog seismic activity of magnitude 2.0 and higher. A catalog of events are available here: http://www.beg.utexas.edu/texnet-cisr/texnet/earthquake-catalog. Occidental also accesses the USGS Advanced National Seismic System.

Faults can be found in all reservoirs, and Occidental's are no different. In the course of field development, 30 seismic shoots were conducted that identified faults present in Occidental's reservoirs. We found relatively few that penetrate the reservoir interval. None of these faults are believed to breach the regional seal, a finding supported through more than 40 years of injection history. Time-lapse, or 4D, seismic monitoring of CO_2 is not possible in Occidental's Permian Basin reservoirs due to the lack of baseline (pre-CO_2 flood) data and reservoir properties are not conducive to seismic fluid substitution calculations. Namely, the reservoir he rock is dense dolostones, which feature fast velocity and low seismic resolution. Porosity is low to moderate at 4% to 15% and burial depth is great at 5,000 ft to 7,000 ft. Rather than rely on seismic data with poor resolution due to the reservoir's properties, Occidental relies on direct measurement of CO_2 concentration and pressure at its wells. These direct measurements enable us to monitor injected CO_2 with greater accuracy than direct seismic data.

Furthermore, Occidental's enhanced oil recovery operations vary from several hundred to several thousand wells, both injectors and producers. E.g., at our Denver Unit, we operate more than 1700 wells including 600 injectors. These wells feature close spacing on the order of 600 ft to 2,000 ft. Downhole seismic monitoring of each closely spaced well would be redundant and unnecessary and is simply not feasible. The current seismic monitoring available through CISR provides resolution greater than the 2.7 resolution proposed by CARB combined with our SCADA system renders downhole seismic monitoring redundant and unnecessary.

We recommend that CARB revise the proposed protocol language to recognize that existing surface-based seismicity measuring systems allow for monitoring of events of lower magnitude than 2.7.

We suggest the following revisions to C.4.3.2.3:

(a) The CCS Project Operator must either:

1. deploy and maintain a permanent, downhole seismic monitoring system in order to determine the presence or absence of any induced micro-seismic activity within the vicinity of all wells and near any discontinuities, faults, or fractures in the subsurface, or

2. Participate in a state or regional seismic study zone designed to (1) monitor, locate, and catalog seismic activity with magnitudes of M 2.0 and larger, (2) improve the CCS Project Operator's ability to rapidly investigate and respond to ongoing earthquake sequences, and is publically available. The design of an array should consider the seismic risk. Location of small events can be helpful in risk reduction, but sufficient planning is needed to collect and analyze the data.
3. Analysis of the microseismicity must consider if the risk of triggering an earthquake of Richter magnitude 2.7, or greater, is significantly increased by injection. If an increase in risk is detected and determined, mitigation of the risk is required; and
4. The array should be calibrated with check-shots, preferably at depth.

(OCCIDENTAL4_FF37-7)

Agency Response: Please see Responses M-3.1 and M-17.5 in Chapter IV related to downhole micro-seismic monitoring. Staff would like to emphasize that the requirement is for a monitoring *system* that can detect seismic activity *associated* with the wells, it is not necessary, or productive, to deploy geophones at each well.

Staff also points out that subsection C.4.3.2.3(b) of the Protocol does require operators to continuously monitor state or regional seismic networks, such as the California Integrated Seismic Network or the U.S. Geological Survey's National Earthquake Information Center and Advanced National Seismic System, or equivalent jurisdictional network.

M-10.4. Multiple Comments: *Pressure Fall-Off Test Requirements*

Comment: C.4.3.1.5(a) requires CCS Project Operators to perform a pressure fall-off test for <u>each</u> well once every five (5) years

CO_2-EOR operations conduct fall-off tests to monitor reservoir pressure so that the reservoir pressure is never higher than reservoir fracture pressure, thereby avoiding fracture propagation and the corresponding risk of a CO_2 release outside of targeted injection interval. Occidental accomplishes this by monitoring reservoir pressure during fall off tests in our injectors and build up tests in our producers. We have found that our reservoir pressures do not change significantly from one area to the other. In addition, because we maintain an injection to withdrawal ratio ("IWR") near 1.0, our reservoir pressure does not increase noticeably through time.

Due to Permian reservoirs having low permeability, each fall-off test takes two weeks to a month to complete. Our enhanced oil recovery operation have hundreds and sometime thousands of injection wells. Continuously or regularly conducting fall-off tests would be an inefficient method of maintaining reservoir conditions. As a result, in addition to the fall-off tests, Occidental relies on its SCADA system to maintain and continuously monitor field pressure to ensure that its injection wells are operating as intended; injecting below fracture pressure. This system enables us to maintain

reservoir pressure by setting injection pressure setpoints for each injector at 50 psi below fracture pressure as established from step rate tests or nearby producers fracture data. This approach automates our processes, provides continuous information on injection well performance, enables Occidental to respond to any issues rapidly, creates a verifiable performance record and is more efficient.

Occidental suggests revising section C.4.3.1.5(a) to permit a range of options for operators:

CCS Project Operators must monitor for changes in the well bore environment that may indicate fluid leakage through the wellbore. Monitoring may include fall-off test of each well at least once every five years pursuant to subsection C.4.1 or other methods approved by the Executive Officer. (OCCIDENTAL4_FF37-6)

Comment: C.4.1 (a)(8) requires a pressure fall-off test at least once every five years, pursuant to subsection C.4.3.1.5, unless more frequent testing is required by the Executive Officer based on site-specific information.

Occidental does perform fall-off tests. However, similar to mechanical integrity testing pursuant to C.4.1 (a)(7), the need for periodic fall-off tests has been largely obviated at enhanced oil recovery operations by sophisticated control systems. As explained in greater detail above, Occidental's SCADA system provides continuous monitoring of field conditions. Consequently, fall-off tests are now conducted much less frequently because field and well conditions are continuously monitored and reported. We suggest the following revision to recognize this operational reality:

C.4.1 (a)(8). A pressure fall-off test on a schedule agreed to with the Executive Officer pursuant to subsection C.4.3.1.5. (OCCIDENTAL4_FF37-17)

> **Agency Response:** Based on the information provided in these comments, staff understands that there are examples of injection projects in which pressure fall-off tests have been obviated by control systems and alternative testing methods. Staff also acknowledges the lack of pressure elevation in active EOR fields. In response to these comments, staff revised subsection C.4.3.1.5(a) of the Protocol to allow for an alternative test method and/or schedule for pressure fall-off tests, provided the project operator meets specific criteria and receives approval for the alternative test method and/or schedule from the Executive Officer prior to operation.

M-10.5. ***Corrosion Monitoring***

Comment: C.4.1.(a)(3) requires corrosion monitoring of well materials upon completion and a minimum of once every five years thereafter ... to ensure that well components meet the minimum standards for material strength and performance set by API, ASTM International, or equivalent. ...

All wells that Occidental has installed at its CO_2-EOR operations were installed in accordance with consensus standards developed by national and international standard

setting organizations, including API and ASTM International standards. As explained earlier, Occidental's CO_2-EOR operations feature hundreds to thousands of wells, both injectors and producers. Where a CCS project operator has hundreds to thousands of wells, monitoring of a statistically significant number of wells, rather than all wells, is appropriate. We suggest the following revision to recognize this well requirement:

C.4.1 (a)(3) Corrosion monitoring of well materials, upon well completion and a minimum of once per every five years thereafter, for loss of mass, thickness, cracking, pitting, and other signs of corrosion, to ensure that well components meet the minimum standards for material strength and performance set by API, ASTM International, or equivalent, by:

(A) Analyzing corrosion coupons from the construction materials a statistically significant number of well placed in contact with the CO_2 stream; or

(B) Routing the CO_2 stream through a loop constructed with the material used in the well and inspecting materials in the loop;

(C) Performing casing inspection logs; or

(D) Using an alternative method approved by the Executive Officer. (OCCIDENTAL4_FF37-15)

> **Agency Response:** The rate of corrosion of well materials can vary depending on the specific materials of construction and the specific environmental conditions to which these materials are subjected. Therefore, an analysis of a statistically significant number of wells every five years may miss certain wells or well components that have corroded more quickly and are nearer to failure. To avoid a potential increase in well failures and CO_2 releases due to corrosion, staff did not modify subsection C.4.1(a)(3) of the Protocol. Staff also notes that subsection C.4.1(a)(3) provides four options for corrosion monitoring of well materials, including an option to propose an alternative method of corrosion monitoring for approval of the Executive Officer.

M-10.6. ***Annual Mechanical Integrity Demonstration***

Comment: Section C.4.1(a)(7) requires a demonstration of external mechanical integrity at least once per year until the injection wells is plugged.

Occidental relies on its sophisticated process controls to monitor mechanical integrity. Even with continuous process control monitoring, periodic external mechanical integrity tests are a critical component to verify injection well performance. Occidental has determined that with its SCADA system, mechanical integrity tests no less often than once every five years provides a superior level of confidence in injection well integrity. In addition, where an operator has hundreds of injection wells, a MI test interval of five years means that dozens if not a hundred or more wells are undergoing testing in any given year. This yields an enormous amount of mechanical integrity data for the operator and, assuming compliance with other protocol provisions, CARB. E.g., at

Occidental's Denver Unit, a MI test interval of at least once every five years means that 120 injectors will be checked every year. If there are mechanical integrity issues, they will be found. We suggest the following revision to recognize this operational reality:

C.4.1(a)(7). A demonstration of external mechanical integrity pursuant to subsection C.4.2 on a schedule agreed to with the Executive Officer, but in no event less frequent than once every five years, taking into consideration the number of active injectors at a CCS Project and, if required by the Executive Officer, a casing inspection log pursuant to requirements at subsection C.4.2(c) at a frequency established in the Testing and Monitoring Plan; (OCCIDENTAL4_FF37-16)

> **Agency Response:** Based on the information provided by the commenter, staff recognizes that there are injection projects in which the density of wells may allow for a staggered approach to external mechanical integrity testing at intervals greater than one year sufficient to identify mechanical integrity issues in the project wells. Therefore, staff revised subsection C.4.1(a)(7) to require, "A demonstration of external mechanical integrity pursuant to subsection C.4.2 at least once per year, or on a schedule approved by the Executive Officer, but not to exceed once every five years, until the injection well is plugged,…"

M-10.7. *Mechanical Integrity Demonstration Prior to Well Plugging*

Comment: C.4.2(b)(6) requires demonstration of mechanical integrity prior to plugging a well.

This appears to be a redundant requirement already satisfied elsewhere. In the event a MI test finds that a well's mechanical integrity is compromised, one solution is plugging and abandoning the well. In the case of this provision of the protocol, a P&A of the well is already planned. An MI test is a needless requirement. We suggest deleting this requirement. (OCCIDENTAL4_FF37-18)

> **Agency Response:** Subsection C.4.2(b)(6) of the Protocol requires the CCS Project Operator to demonstrate *external* mechanical integrity prior to plugging a well. This requirement applies to wells that have not recently undergone mechanical integrity testing, such as an observation well that is no longer in use. This requirement is necessary because well plugging may not prevent external fluid movement out of the sequestration zone through channels adjacent to the wellbore.

M-10.8. Multiple Comments: *Soil and Environmental Monitoring Methods*

Comment: However, we remain concerned by the persistence of soil methods in several parts of the proposal. As we have commented previously to ARB, soil gas methods such as those required during the post-injection period in proposed §5.2(b)(G)(1), and as a *recommended* method in proposed §2.5(c)(5)(B), are known to suffer from inherent limitations and may not be effective in detecting CO_2 in the shallow subsurface. (CATFNRDC1_FF55-25)

Comment: We recognize that the rule will require an operator to demonstrate, during the injection period MMV, that leakage signals from soil flux methods will be effective (proposed §4.3.2.2(c)). However, a demonstration of sensitivity is not a requirement of post injection monitoring and may prove unrealistic for the injection period MMV as well, given that many years may be required to establish representative soil gas concentrations. Moreover, establishment of a baseline might not be possible given that climate change may result in changes in soil gases which further confound the use of a baseline approach.

Therefore, we strongly discourage the reliance on any baseline soil and air method in the rule. If soil methods are to be employed, they should be *process-based* methods that are implemented to determine sources of leakage once it has been identified, and do not require a baseline, as recommended by the University of Texas at Austin Gulf Coast Carbon Center. (CATFNRDC1_FF55-26)

Comment: Research has been conducted in areas with natural CO_2 seeps or in controlled release experiments to test the efficacy of vegetation stress monitoring to detect CO_2 leakage. While the use of remote sensing techniques to detect plant stress has shown some promise in identifying CO_2 leak sites, there is also a high incidence of both false positives and false negatives, given that there are many factors affecting plant health. Applying these techniques successfully requires significant, site-specific experience and is most appropriately used to supplement other monitoring techniques.

ARB's proposal that monitoring be conducted yearly is not sufficiently justified and fails to account for seasonal and other variations in plant cover and health; the appropriate monitoring frequency must be site-specific. Additionally, some sites may not be appropriate for such monitoring techniques, as the presence of vegetation is clearly a key prerequisite. We recommend that instead of mandating the use of vegetation surveys, ARB require operators to assess the efficacy of such surveys on a site-specific basis, as part of a holistic assessment of appropriate surface and near-surface monitoring techniques. (CATFNRDC1_FF55-29)

> **Agency Response:** Staff acknowledges the limitations and potential for errors of proposed soil-gas methods. As noted in Responses M-13.2 and M-15, staff replaced prescriptive soil-gas monitoring requirements with strategies that are more flexible and performance based. Please see Response M-15 in Chapter IV and Response M-4.2 in this chapter regarding revisions to the Protocol associated with prescriptive soil-gas and air monitoring requirements.

M-11. Multiple Comments: *Permanence Certification Transfer*

Comment: Section C.1.2.(b) provides that the Permanence Certification is non-transferrable. Should this CARB effort create a successful and robust market, it is expected that the Permanence Certificate will have significant value. Value generated not only through the LCFS credits but value created by a party's skill in qualifying for the generation of LCFS credits. This value may be monetized through the sale of a CCS project. Where a corporate entity is sold, there will be no question that the new owner

of the company holds the Permanence Certificate. The same should hold true if the asset is sold. In such cases, the Permanence Certificate for the asset should be able to be transferred to the new owner, along with any accompanying obligations, where the parties to the transaction provide notice to CARB and the new owner can demonstrate compliance with the protocol.

We suggest revising the language as follows:

The Permanence Certification is may be transferable where the transferee demonstrates that compliance with LCFS and this protocol. (OCCIDENTAL4_FF37-9)

Comment: Regarding the proposed actions under §2.4.4(d), we believe that it would be appropriate to revoke the Project Certification in some cases, but not all. For example, if the CO_2 has migrated into a neighboring lease where land and subsurface access is impossible, or if it has intercepted a leakage pathway that is difficult or impossible to control or monitor, then such revocation would be desirable. But there may be cases when the plume simply breaches the defined Storage Complex without any consequences and without any increased atmospheric leakage risk. In such cases, redefining the Storage Complex may be sufficient. We recommend that the Executive Officer reserve the right to revoke the Project Certification in cases where it is warranted, which would include negligence, fraud and materially increased risk of atmospheric leakage. Such authority would act as a deterrent to defining the Storage Complex too narrowly and drive precautionary behavior. (CATFNRDC1_FF55-20)

> **Agency Response:** Subsection C.8.2(a)(4) of the Protocol allows for a change in ownership or operational control of a CCS project where the Executive Officer determines that no other change in Permanence Certification is necessary, provided that a written agreement containing a specific date for transfer of responsibility, coverage, and liability between the current and new CCS Project Operator has been submitted to the Executive Officer. Essentially, if change of ownership occurs, and no other provisions need to be updated a new permanence certification may be issued for the same entity, but the original certification is non-transferable without this additional analysis based on the change in ownership.
>
> Subsection C.8(a) of the Protocol allows the Executive Officer to modify or revoke and reissue a Permanence Certification if he or she determines that one or more of the causes listed in subsections C.8(b) or C.8(c) exist. For the example provided by the commenter (i.e., a CO_2 plume that has migrated outside of the storage complex), the Executive Officer would determine whether the Permanence Certification could be modified based on a reevaluation of the storage complex under subsection C.2.4.4 of the Protocol, as indicated in subsection C.8(b)(5)(A) of the Protocol. Subsection C.8.1 of the Protocol specifies the causes for which the Executive Officer may terminate a Permanence Certification during its terms or deny a Permanence Certification renewal application.

M-12. ***Accounting Requirements***

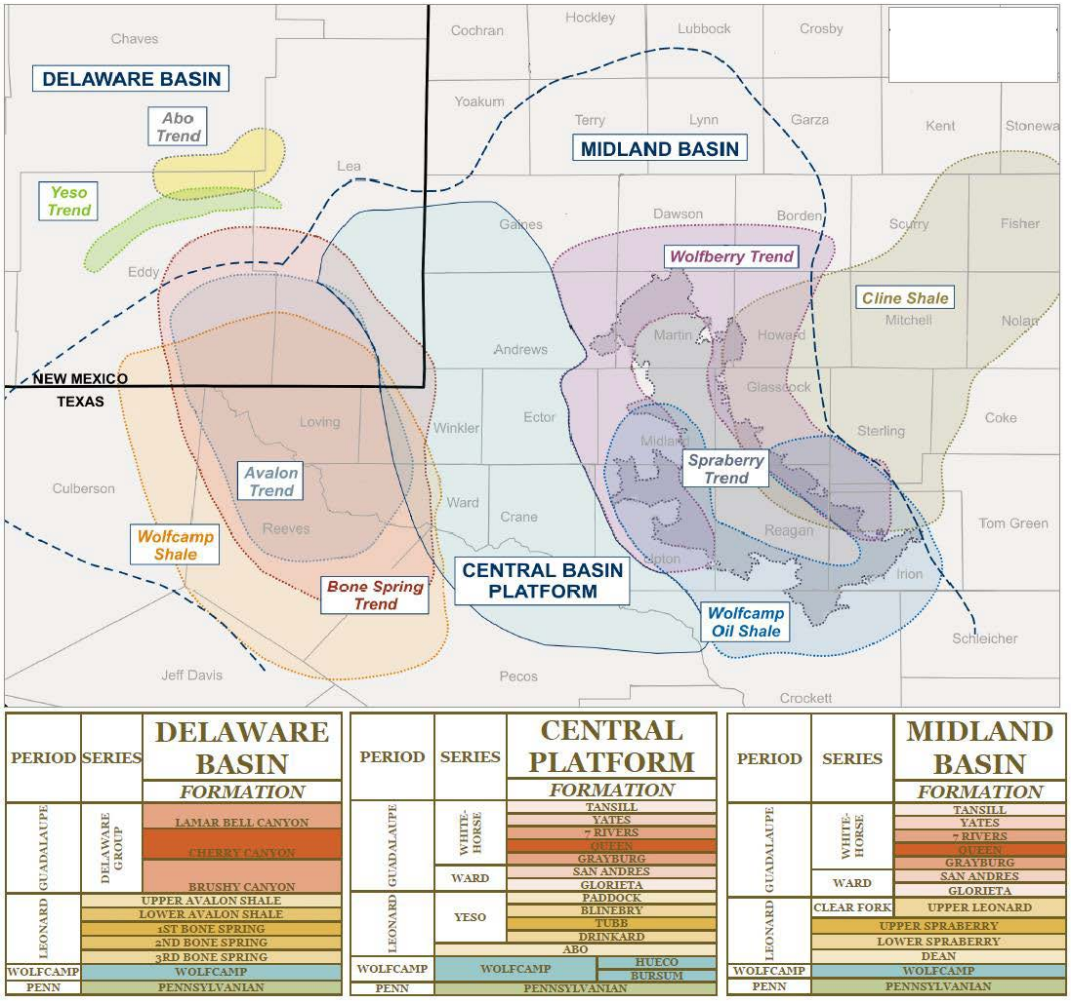
Comment: On a similar note, we do not agree that credits should be invalidated for subsurface leakage unless it can be shown that actual atmospheric leakage has occurred or is likely to occur as a result of subsurface leakage. In some cases, subsequent atmospheric leakage may be inevitable if the subsurface leakage has resulted in the CO_2 intercepting a pathway that would provide a path to the surface. In other cases, though, the CO_2 may remain permanently trapped in the subsurface, even if it has breached the originally defined Storage Complex. We believe the potential revocation of the Project Certification to be sufficient disincentive for projects to define the Storage Complex too narrowly, and that accounting under the LCFS should be concerned with actual atmospheric emissions – not inconsequential migrations in the subsurface. As such, the proposed revisions to the term $CO_{2leakage}$ in equations (5) and (6) under §2.2(e) should be struck. In addition, we would like to draw ARB's attention to the case of a reservoir that is compartmentalized. Such "blocks" are known to occur in practice and may or may not be hydrologically isolated. We presume that all blocks would be part of the same Storage Complex. If they are indeed isolated in the subsurface, breaching the Storage Complex in one block would not mean that the security of storage in the others is compromised. We recommend a scaling approach based on injected quantities for the purposes of accounting for leakage and credit invalidation in such cases. (CATFNRDC1_FF55-21)

> **Agency Response:** Please see Responses M-8.4 and M-8.6 in Chapter IV regarding difficulties in verifying permanent sequestration of migrated CO_2 and crediting based on real, additional, and verifiable GHG emissions reductions, respectively. Based on these responses, and in an effort to maintain the environmentally conservative accounting basis of the CCS protocol, staff retained the revisions to the term $CO_{2leakage}$ in Equations (5) and (6) in subsection B.2.2(e) of the Protocol. In response to the commenters' recommendation to use a scaling approach for the purposes of accounting for leakage and credit invalidation from compartmentalized Storage Complexes, please see Response M-8.4 in Chapter IV, which also includes staff's response regarding the development of methods to more accurately quantify off-lease migration.

M-13. Multiple Comments: ***Binding Agreements***

Comment: C.9(c). The CCS Project Operator must show proof that there is a binding agreement among relevant parties that drilling or extraction that penetrate the confining layer above the sequestration zone is prohibited within the AOR.

We understand the intent behind this provision is to ensure there is not movement of stored CO_2 out of the intended sequestration zone and above the storage complex or to the atmosphere. In oil and gas development, split estates, where the mineral estates and surface estate are owned by different parties are common. Different mineral estates underlying a single surface estate often exist at several different depths. For example, the Permian Basin consists of several basins, each with multiple formations lying at different depths, as illustrated in the figure below:



CO_2-EOR projects already take place in different formations that lie at different depths that are owned by different parties. Drilling through multiple formations is a technical challenge with engineered solutions. Drilling through multiple formations that may be owned by different parties requires drillers to set casing strings to prevent mixing of different zones. These same techniques safeguard freshwater aquifers from cross contamination as well as preventing the mixing of brackish water with freshwater. These same engineered solutions prevent the release of CO_2 from a CO_2-EOR project during the drilling and construction of wells.

Given the engineered solutions that are already available and in use, it is not necessary for relevant parties to meet an agreement that prevents drilling through one formation to access another formation – an activity that already occurs. While it is not possible to predict with certainty whether future technology will permit development of deeper formations that may underlie a CO_2-EOR project, past experience indicates that this is highly likely to occur. Owners of surface estates and mineral estates are aware of this likelihood and are reticent to take their property permanently out of production at any cost. Particularly, at the outset of a CCS Project. Assuming that a transition to a lower carbon intensity economy continues throughout this century, we do expect that relevant

parties will be more amenable to reaching an agreement to prohibiting the advance of penetrations into other formations in the future. But it is not certain.

To account for these issues, and to still provide CARB the assurances it seeks, we suggest revising the language as follows:

"C.9(c). Upon injection completion, the CCS Project Operator must show proof that there are sufficient safeguards in place to prevent leakage from the sequestration zone. These safeguards may include:

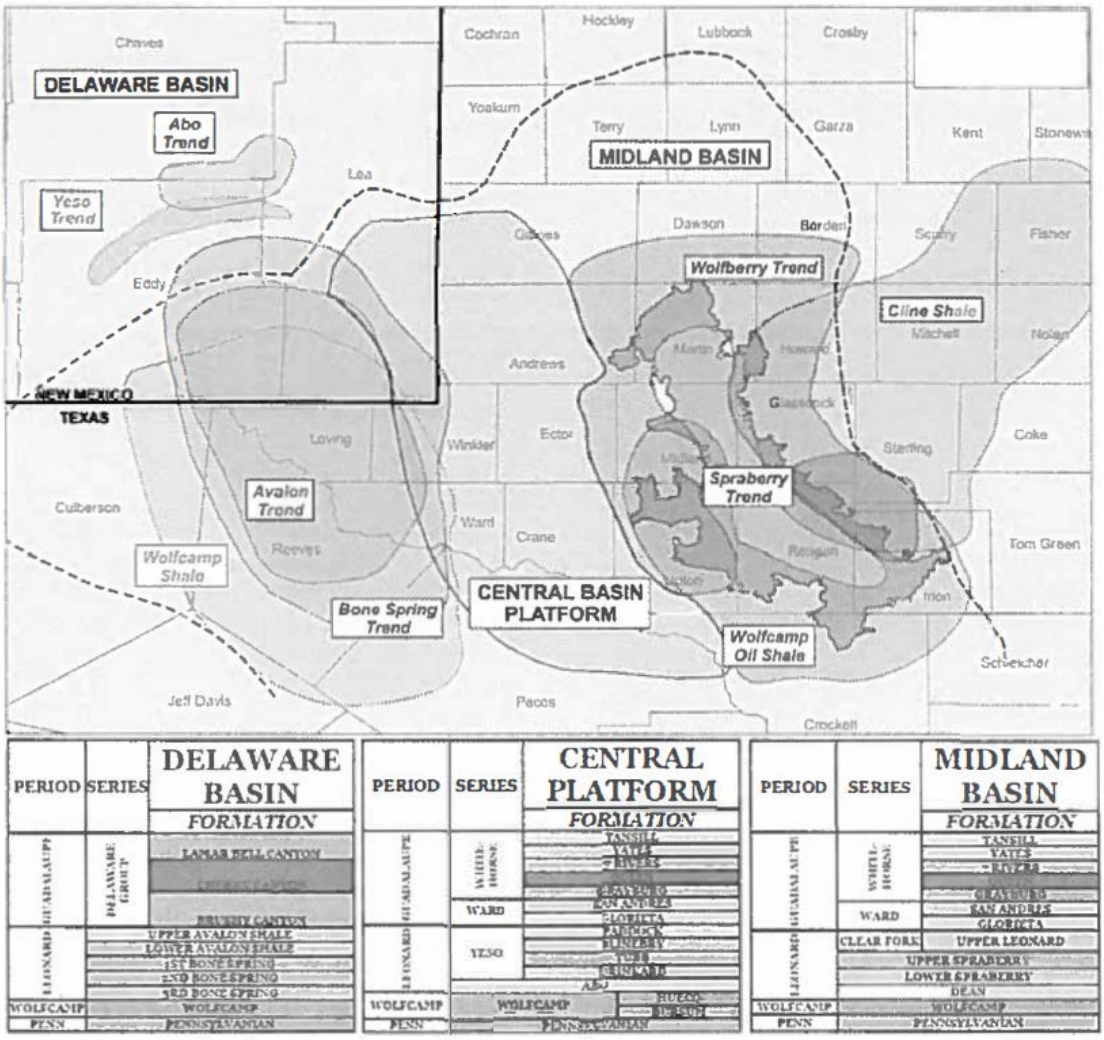
(1) A binding agreement among relevant parties that drilling or extraction that penetrate the confining layer above the sequestration zone are prohibited within the AOR;

(2) Enforceable regulatory or other legal mechanisms that require wells that penetrate the confining layer above the sequestration zone to prevent unauthorized mixing or loss of fluids from the sequestration zone and confining layer."

(OCCIDENTAL3_FF1-17)

Comment: C.9.(c) requires the CCS Project Operator to show proof of a binding agreement among relevant parties that drilling or extraction that penetrates the storage complex is prohibited.

We understand the intent behind this provision is to ensure there is not movement of stored CO_2 out of the intended sequestration zone and above the storage complex or to the atmosphere. In oil and gas development, split estates, where the mineral estates and surface estate are owned by different parties are common. Different mineral estates underlying a single surface estate often exist at several different depths. For example, the Permian Basin consists of several basins, each with multiple formations lying at different depths, as illustrated in the figure below:



CO_2-EOR projects already take place in different formations that lie at different depths that are owned by different parties. Drilling through multiple formations is a technical challenge with engineered solutions. Drilling through multiple formations that may be owned by different parties requires drillers to set casing strings to prevent communication and mixing between different zones. These same techniques are used to protect underground sources of drinking water ("USDW") as well as safeguard freshwater aquifers from cross contamination and prevent the mixing of varying concentrations of brackish water present at different subsurface depths. These techniques have been successfully employed for over 100 years and are regulated by the Clean Water Act, the Safe Drinking Water Act and state law. These same engineered solutions prevent the release of CO_2 from a CO_2-EOR project during the drilling and construction of wells.

Given the engineered solutions that are already available and in use, it is not necessary for relevant parties to meet an agreement that prevents drilling through one formation to access another formation - an activity that already occurs. While it is not possible to predict with certainty whether future technology will permit development of deeper

formations that may underlie a CO_2-EOR project, past experience indicates that this is highly likely to occur.

Further, should economic quantities of oil and gas be found in a formation below a formation used to sequester CO_2, there is no current legal pathway for an owner of one mineral estate to prohibit drilling by a company with a property interest in a different mineral estate. In California, Texas and New Mexico, an owner of a mineral estate has the exclusive right to drill for oil and gas and to retain all substances brought to the surface. *Callahan v. Martin* (1935) 3 Cal.2d 110. That is, the mineral estate is the "dominant" estate. As the owner of the dominant estate, the owner of the mineral estate has the right to use the surface estate "as is [reasonably] necessary and convenient" to extract minerals and (if necessary) may preclude other surface uses. *Id*. These rights are specific only to the mineral estate. *Id*. The surface owner retains all rights not held by the mineral owner and may not unreasonably interfere with the operation of the mineral estate. *Cassinos v. Union Oil Co. of Cal.* (1993) 14 Cal.App.4th 1770.

Owners of surface estates and mineral estates are aware of the legal landscape, the likelihood that their property may be developed in the further and are reticent to take their property permanently out of production at any cost.

To account for these issues, and to still provide CARB the assurances it seeks, we suggest revising the language as follows:

C.9(c). Upon injection completion, the CCS Project Operator must show proof that there are sufficient safeguards in place to prevent leakage from the sequestration zone. These safeguards may include:

(1) A binding agreement among relevant parties that drilling or extraction that penetrate the confining layer above the sequestration zone are prohibited within the AOR;

(2) Enforceable regulatory or other legal mechanisms that require wells that penetrate the confining layer above the sequestration zone to prevent unauthorized mixing or loss of fluids from the sequestration zone and confining layer.

(OCCIDENTAL4_FF37-8)

Agency Response: Staff acknowledges the concerns regarding the need for binding agreements and solutions currently in place to prevent communication and mixing between different zones. However, without binding agreements in place, CARB cannot ensure the long-term permanence of the sequestration. Please also see Response M-23 in Chapter IV.

M-14. *Deed Notification Requirements*

Comment: C.5.2(f). Within 30 days each CCS Project Operator must record a notation on the deed of the CCS project property…that will in perpetuity provide any potential

purchaser of the property the following….(1) the fact that the land has been used to sequester CO_2….

This provision is similar to C.9(b), which requires that full disclosure must be made to inform future land management or development within the AOR. For example, the restrictions and disclosure must be recorded on the deeds of the land when no regulations are in place to address this issue.

Occidental suggests that compliance with either provision should satisfy the notice requirement CARB seeks. Further, a demonstration of compliance with either provision should not be required until the project enters the Post-Injection Site Care period. Finally, Occidental suggests that a 30-day period is too brief to permit a project operator to complete deed recordation for a CO_2-EOR project that may underlie properties owned by multiple unrelated parties.

We suggest the following revision:

C.5.2(f). Within three years after the project enters the Post-Injection Site Care period, each CCS Project Operator must disclose…to any potential purchaser of the property the following….(1) the fact that the land has been used to sequester CO_2…or demonstrate that existing regulations are in place to provide notice to potential purchasers. (OCCIDENTAL3_FF1-16)

> **Agency Response:** Please see Response M-14 in Chapter IV related to length of time to complete the deed notation. Staff acknowledges that the deed notification requirement in subsection C.9(b) of the Protocol is similar to the notification requirement in subsection C.5.2(f) of the Protocol. However, because the provision in subsection C.9(b) of the Protocol does not contain a timeframe for completion of deed notification, staff does not agree with the commenter that compliance with either provision would satisfy the notice requirements CARB seeks. The provision in subsection C.9(b) does not conflict with the provision in subsection C.5.2(f), therefore, staff retained both provisions.

N. Reporting and Recordkeeping

N-1. *Support for the Proposed Modifications to the Reporting and Recordkeeping Provisions*

N-1.1. Multiple Comments: *Support for the Proposed Extension of the Obligation Transfer Period for Liquid Fuels*

Comment: WSPA appreciates the extension of the period in which credit or deficit generator status can be transferred to another entity, for a given amount of fuel, to three calendar quarters. (WSPA5_FF19-4)

Comment: Calgren Renewable Fuels would like to support the proposed extension of the transfer period for credit or deficit generator status. Our recommendation is to extend the period to four quarters. It is our belief the extension will provide additional support to obligated parties to accurately generate and transfer credit, especially credits generated by a dairy digester cluster. Dairy digesters are often operated at ambient temperatures, thus causing their output to be almost twice as great in the summer heat as opposed to the winter cold. Storage of biomethane may be required in order address this seasonality. Allowing four quarters of flexibility would match up well with the inherent seasonal swings and allow for this contemplated storage. (CRF2_FF42-1)

Comment: REG supports … changing the transfer period in (a)(3) from two quarters to three quarters. (REG3_FF44-6)

> **Agency Response:** Staff appreciates the commenters' support for the proposed extension of the Obligation Transfer Period from two quarters to three quarters.

N-1.2. *Support for the Proposed Fuel Transaction Reconciliation Requirements*

Comment: REG supports the clarification in 95486(a)(l)(B) with the reconciliation requirements being on obligated amounts. This will help avoid potential issues below the rack and other sales without obligation. (REG3_FF44-9)

> **Agency Response:** Staff appreciates the commenter's support for the proposed clarification for the reconciliation requirements for generating credit and deficit.

N-2. *Proposed Obligation Transfer Period for Liquid Fuels*

Comment: Under the proposed Section 95483(a)(3) Transfer Period, the ability to transfer a Fuel Reporting Entity's credit or deficit generator status is limited to three calendar quarters. The implications of imposing a time limit on the transfer of the credit/deficit generator status are undesirable because they can impinge on a party's ability to effectively balance supply-demand requirements and impose complex reporting and recording keeping requirements on producers who may be less sophisticated, resulting in additional costs and regulatory burden. If any time limit is to be imposed, one calendar year from production or import would provide parties with

more flexibility and the ability to appropriately manage demand needs in the market. (BP2_FF8-2)

Agency Response: When a credit or deficit generator balances the inventory of the same fuel in the LRT-CBTS across compliance years, the accounting of credits or deficits is skewed as credits and deficits are proportional to the difference between the CI of fuel and the CI benchmark in the year. As fuel inventory is rolled over from one year to another the credit or deficit generation potential of fuel also changes with the change in annual CI benchmark.

To avoid such situation and ensure an accurate accounting of credits and deficits in the program, the transfer of credit or deficit generator status for a liquid fuel quantity should not occur inter-year and, ideally, be limited to a single quarter. Staff understands the commercial practices in the industry require some flexibility and initially proposed a two-quarter limit on transferring the credit or deficit generator status to another entity. However, considering on stakeholder inputs requests staff proposed to extend the transfer period from two quarters to three quarters. The longer the transfer period the higher is the risk of inventory rollover to a different year resulting in potentially skewed accounting of credits or deficits.

Staff would like to note, once the transfer period is over the ownership of the fuel can still be transferred without obligation (meaning, without the ability to generate the associated credits by the buyer), and the resulting credits or deficits would be retained by the upstream entity, which can transfer any credits separately in the LRT-CBTS.

N-3. ***Proposed Change of Ownership or Operational Control Provisions***

Comment: We continue to be concerned by the drafted change of ownership rules as noted in our initial comments prior to the Board hearing which are elaborated on below.

1) A deal could fall through and ultimately not occur, but the change in notification would have already been made which would necessitate another change notification which will confuse the issue.
2) Entities in the deal may not legally be able to disclose prior to completion of the deal. Notification to CARB may violate an NDA, as well as possible state specific laws impact commerce; lastly, such provisions may be impossible to reconcile with SEC reporting requirements for public companies.
3) Notification to CARB would be of public record that by itself, may impact the ability to close.

We suggest CARB consider the requirement of notification paperwork to occur prior to the next quarterly submission of credits or within some reasonable time frame, say 45 days subsequent to the actual change in ownership. (REG3_FF44-7)

Agency Response: Please see Response N-5.2 in Chapter IV.

N-4. Multiple Comments: ***LCFS Reporting and Credit Issuance Timelines***

Comment: REG remains **adamantly opposed** to credits being generated on the day after the reporting deadline per (b) unless those deadlines are moved up. As noted in prior comments, there are financial impacts from this proposal.

To highlight some of these impacts, let us examine a factious biodiesel plant as an illustrative example.

> Plant A sells eight million gallons in California annually with fifty percent being sold without obligation (4M creditless). Assuming an average CI of 35 with a 98.44 benchmark with a $151.78 LCFS credit price (weekly high average). This equates to 32 thousand credits annually to sell. Using the above assumptions, that equates to $4,857,984.33 (32K x $151.78). Using a LIBOR + 1.75% as a proxy, that is an annual net working capital cost of $187,032.97. This plant also takes on risk associated with the changing market value of the LCFS credits. Our risk management team puts that cost at $10/credit based upon historical volatility of credit values or $320,000 total in this scenario. So potentially that is a $0.127 per gallon cost for those gallons sold without obligation ((187K+320K)/4M) from this proposed change.

We have continued to maintain that the potential benefits of the shift do not outweigh the added costs. Therefore, we continue to strongly encourage CARB staff to keep the system as is or move up the deadlines to the 20th of the last month. Regardless, we believe Staff should model the impact of this proposed change in order to understand how reduced sales of biodiesel could impact the updated carbon reduction goals. (REG3_FF44-11)

Comment: As noted 95486, **REG strongly advocates to keep the credit generation system as is**. However, if it is changed so that no credits can be generated until after the reporting period is over, then we strongly recommend changing the reporting frequency and deadlines from 45/45 to 45/35 with deadlines being the 20th of the final month (June, September, December, and March) to avoid financial statement impacts (see our detailed comments earlier in this document). (REG3_FF44-38)

> **Agency Response:** Please refer to Response N-7.2, LCFS Reporting and Credit Issuance Timelines, in Chapter IV.

N-5. ***Proposed Product Transfer Documents Requirements***

N-5.1. Comment: *Section 95491.1(b)(1)(C) Documenting Fuel Transfers Reported in the LRT-CBTS*

Under the existing regulation, this section provides a reporting party the ability to specify the Transaction Date as either the Date of Title Transfer (for Non-Aggregated Transactions) or the Quarter End Date (for Aggregated Transactions). However, in the proposed amendments, this wording has been deleted and replaced with “Date of Title Transfer for Fuel.” For Natural Gas, where delivery is occurring daily throughout a

delivery period, the requirement to list every day that fuel is delivered will be administratively burdensome for both reporting entities and CARB - and seems extremely inefficient. Currently, aggregating these data to quarter end is consistent with the LCFS reporting obligations and manageable for all participants. Changing this to a daily requirement will increase costs in terms of reporting the flow daily and creating PTDs. We do not believe that it is CARB's intention to require parties to report daily transfers for these types of transactions. We request that the intent of this amendment is clarified by staff. (BP2_FF8-3)

> **Agency Response:** Staff amended the proposed Regulation to clarify that the requirements set forth in section 95491.1(b), referenced here by the commenter, are only applicable to Product Transfer Document (PTD) provided by a fuel reporting entity pursuant to section 95483(a) *Fuel Reporting Entities for Liquid Fuels.* This means the PTD requirements apply only to fuels that can be reported as sold or purchased in LCFS. Therefore, the natural gas transactions are not subject to PTD requirements. Further, the intent of the proposed amendment is to ensure any title transfer of obligated fuel is properly recorded in the form of PTD. However, the fuel reporting entity would still be able to report multiple transactions as an aggregated transaction in the LRT-CBTS.

N-5.2. Comment: REG has concerns about a few changes proposed to the PTD requirements in (b)(1). First, the change to (b)(1), (b)(1)(F), (b)(2), and (b)(2)(B) will needlessly complicate transactions; we recommend keeping the current language as is ("LCFS obligation is passed."). For instance, when REG is passing obligation in the state of California, the credits have already been generated since they are generated off of import. Under the proposed change, a statement saying, "the LCFS obligation to act as credit generator," would imply a second generation of credits.

Another option might be to change LCFS obligation to" LCFS credit obligation" or "LCFS deficit obligation is being passed," though it is not our preference. We'd prefer that the PTD requirements be relatively similar to the LRT reporting options. In this case, "LCFS obligation is passed" is closer to the Transaction Types in LRT (e.g. Sold with Obligation) than "LCFS credit or deficit obligation is passed." (REG3_FF44-39)

> **Agency Response:** Staff proposed the changes referenced in the comment to provide clear instructions for the fuel reporting entities and to use consistent terminology as proposed in the other parts of the regulation. Staff disagrees that the proposed changes would change the meaning of the Product Transfer Document (PTD). Staff would like to clarify if a credit generating fuel is transferred with obligation the associated credits are removed from the seller's account balance and equivalent credits are added to buyer's account balance. This constitutes an act of credit generation and vice versa for deficit-generating fuel.

N-5.3. Comment: Second, we don't recommend changing (b)(1)(C) since it would seem to imply that reporting on aggregation is no longer allowed in LRT – which we do not believe is staffs intent . This will limit flexibility for companies on reporting in the

system and likely negatively impact smaller companies with smaller compliance staffs. (REG3_FF44-40)

> **Agency Response:** Staff would like to clarify that the proposed change would require the fuel reporting entities to obtain Product Transfer Document (PTD) for each fuel transaction; however, the fuel reporting entities would still be able to aggregate the fuel transactions to report in the LCFS Reporting Tool and Credit Bank and Transfer System (LRT-CBTS)

O. Third-Party Verification

O-1. *Conflict of Interest and Availability of Qualified Verifiers*

O-1.1. Multiple Comments: *Firm Rotation Requirements, Availability of Qualified Verifiers, Lookback and Phase-In Period*

Comment: RNG Coalition supports the extended phase-in period for certain services to January 1, 2023 and clarifying language for certain high-risk services, including accounting. As mentioned in our prior comments, we support the concept of third-party verification in order to strengthen the environmental integrity of the LCFS program. However, we are concerned that the system may face challenges due to lack of available services from qualified providers. We believe the extended phase-in period for certain services and clarification language for certain high-risk services will help smooth the implementation process. We thank you for these modifications. (RNGC3_FF46-10)

Comment: DTEBE appreciates the extended phase-in of these conflict of interest rules, and we encourage CARB to monitor the development of the LCFS verification market to ensure there are enough qualified verification providers for large producers to access without harming participation in the LCFS program. (DTEBE2_FF20_6a)

Comment: Verification Program

We believe CARB is taking the right approach by designating provisions §95503(b)(A),(B),(E),(G),(H),(I), &(N) as medium potential conflict of interest within a five-year look back period ending on January 1, 2023. This provides more time for the low carbon fuels suppliers and the auditing industry to adapt their business practices to these new requirements. (ECOENGINEERS2_FF21-7)

> **Agency Response:** Staff appreciates the commenter's support of the verification proposal and extended phase-in period. Staff extended the phase-in period in its Proposed 2nd15-day Modifications to August 31, 2023, to allow verification of 2022 data to be completed prior to rotation of some verification bodies. Please see Response O-2.1 in Chapter IV regarding staff's commitment to monitor verifier availability and qualifications.

O-1.2. Multiple Comments: *Specific Conflict of Interest Requirements*

Comment: However, we still believe some of the definitions of activities that trigger high conflict of interest are too vague and could benefit from revision. Below are some specific examples:

1. EcoEngineers offers a RIN tracking system to the biofuels industry that allows data transmittals from biofuel plants to the EPA for RIN generation purposes. The system acts as a "conduit" that transports producers' data directly from the producers' servers to EPA databases with no interference from EcoEngineers staff or agents. The system also stores it for future retrieval for record-keeping and auditing

purposes. We do not believe this creates a high conflict scenario and it provides our auditors up-to-date information on fuel transaction and credit generation at the facility. Section §95503(b)(2)(A) currently offers an explicit exception to accounting software. We believe EcoEngineers' RIN platform deserves a similar exception.

2. In §95503(b)(2)(C), "Designing or providing consultative engineering or technical services in the development and construction of a fuel production facility; or energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit" is identified as triggering a high conflict. First, consultative engineering is a very broad phrase that is not clearly defined. For example, sometimes one of our engineers may be asked to provide an opinion on whether the LCFS requires the installation of a flow meter at a certain location to measure feedstock or finished fuel flows. We do not believe providing this opinion triggers a conflict of interest; however, the phrase "consultative engineering" can be interpreted to argue that it does. Second, the use of the word "development" in this context greatly broadens the scope of this conflict of interest and could include any task that ultimately helps a facility come into production. We believe that an engineer who is responsible for the design and construction of the facility should trigger a high conflict of interest; however, engineers also often provide independent, third-party opinions which ultimately assist projects make good decisions. These independent, third-party opinions should not be identified as triggering a high conflict of interest.

3. Section §95503(b)(2)(L) identifies "appraisal services of carbon or greenhouse gas liabilities or asset," as a service that triggers a high conflict and §95503(b)(2)(C) identifies "consultative engineering" as a service that triggers a high conflict. EcoEngineers sometimes provides its clients the current market value of renewable fuel credits as seen in 3rd party market transactions or other publicly available data such as CARB's website. This data may or may not be part of an independent economic analysis that compares potential future revenues with estimated capital and operating costs at a facility. It is our unbiased, independent opinion that creates value for our clients. We do not believe these services trigger a high conflict, and there should be some allowance for these types of relationships to continue without triggering a conflict.

4. Section §95503(b)(2)(H) triggers a high conflict if a verification body provides "verification services that are not conducted in accordance with, or equivalent to, section 95503 requirements." The EPA's QAP program is currently the most common verification program among U.S. biofuel producers and it is unlikely to be in accordance with section 95503 requirements. We recommend that CARB modify this language to allow current QAP providers to perform LCFS verification activities without triggering any conflict of interest.

<u>Recommended Action:</u>

1. Modify §95503(b)(2)(A) to include an exception for a data transfer system that exchanges RIN data between a facility and EPA databases.

2. Modify §95503(b)(2)(C) as follows: "Designing or providing engineering or technical services in the design and construction of a fuel production facility; or energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit."

3. Modify Section §95503(b)(2)(L) to allow for independent, third-party opinions of credit values or project costs and revenues to be a medium conflict with requirements that the report clearly identify the independence of the opinions within and/or a mitigation plan.

4. Modify section §95503(b)(2)(H) to explicitly create an exemption for QAP services. (ECOENGINEERS2_FF21-8)

Comment: DTEBE noted in its previous comment letter that language around expert services in 95503(b)(2)(U) would cause problems for large companies like ourselves that receive numerous types of expert services unrelated to our biofuels activity. We still have concerns that this conflict of interest language is too narrow and will decrease the number of available verifiers for us to utilize. DTEBE would like to see language amending the conflict of interest conditions. We have provided amended language for this section on expert services below:

> "Expert services to the entity required to contract for verification services solely with respect to a specific project or a legal representative for the purpose of advocating the entity required to contract for verification services interests in litigation or in a regulatory or administrative proceeding or investigation." (DTEBE2_FF20-6b)

> **Agency Response:** Please see Response O-2.3 in Chapter IV regarding specific conflict of interest requirements.

O-2. *CI Pathway Maintenance and Verification – Verification Frequency, Variability of Carbon Intensity, Enforcement for Normal Fluctuating Operations*

Comment: REG supports the updated language in 95501 to allow for quarterly reviews to be done throughout the year rather than artificially waiting to start the audit after the year is over. (REG3_FF44-41)

> **Agency Response:** Staff appreciates the commenter's support for staff's changes in section 95501 regarding quarterly verification review in the context of annual verification. Discussion of quarterly verification review is provided in Response O-4 in Chapter IV.

O-3. *Consider Trial Period to Assess Unforeseen Implementation Impacts, Verification Costs, Market Uncertainty and Credit Invalidation*

Comment: PG&E supports ARB's proposal to improve the quality and accuracy of the LCFS program by requiring third-party verification. However, PG&E remains concerned that some of the Tier 1 and 2 fuel pathways applicants may require additional time to ensure that adequate operational and instrument controls are installed and maintained

to ensure compliance with the LCFS regulation. We are also concerned that the risks and enforcement consequences for not meeting the standards established in the regulation may serve as a deterrent to entry for some credit generators. An unintended consequence of reduced participation would be a reduction in the number of credits available, which in turn would put pressure on the state's ability to achieve its CI reduction target and annual benchmarks.

In order to balance a need for a robust LCFS program and encourage sufficient market liquidity, we recommend that ARB retain the requirement for third-party verification starting in 2021 for 2020 data and implement *§ 95495. Authority to Suspend, Revoke, or Modify, or Invalidate* starting in 2023 for 2022 data. This will allow both regulated entities and verifiers the time needed to meet the detailed requirements of this complex regulation and ensure sufficient liquidity in the LCFS credit market. (PGE2_FF64-6)

Agency Response: Please see Response O-5 in Chapter IV.

O-4. *Verification Miscellaneous*

O-4.1 *Miscellaneous*

Comment: RPMG recommends modifying Section 95491.1(c)(1)(J) to avoid requiring unnecessary recurring Monitoring Plan updates. Section 95491.1(c)(1)(J) requires regulated parties to include the "dates of measurement device calibration or inspection and the dates of the next required calibration or inspection." This provision should be modified to require the regulated party to list the date of the last measurement device calibration or inspection at the time of validation and the frequency at which the device will be calibrated or inspected. Dates of initial calibration or inspection should be provided for devices added following validation. This modification would require the regulated party to supply the same amount of information while not requiring the Monitoring Plan to be regularly updated. (RPMG3_FF41-5)

Agency Response: The commenter's suggestion is permitted in staff's proposal, so no change was made. Under the proposed rules, the monitoring plan must be kept up-to-date and doing so will facilitate an efficient verification. The monitoring plan should refer to the types of records being maintained and the records should be updated. An effective monitoring plan should identify all meters used to measure and monitor data relevant to the reports submitted and specify the calibration frequency.

O-4.2. *Verifier Competency, Guidance, and Fuel Pathway Report Deadline*

O-4.2a. Comment: Can a verifier or verification body who is approved under LCFS but not under Cap and Trade program verify a LCFS pathway for biomethane from dairy and swine manure that claims avoided methane emission credits? (ECOENGINEERS2_FF21-5c, BLUESOURCE1_FF70-6d)

Agency Response: Verification bodies accredited to conduct LCFS verification services, including LCFS pathways for biomethane from dairy and swine manure,

would not be required to also be accredited to conduct Offset Verification Services under the Cap-and-Trade Regulation. Staff anticipates that firms and individuals will be accredited in the latter half of 2019 to perform LCFS verification services beginning in 2020.

O-4.2b. Comment: REG suggests an April 30th deadline versus March 31st for submitting the Fuel Pathway Report to align with finalizing annual reports in LRT. (REG3_FF44-26)

Agency Response: Please see Response O-6.2 in Chapter IV.

O-4.3. Multiple Comments: ***Thresholds and Exemptions***

Comment: Section 95500(b)(2)(B) Deferred Verification states that, "Fuel pathway holders producing alternative **liquid** [*emphasis added*] fuels may defer verification of their annual Fuel Pathway Reports…if the quantity of fuel produced…does not result in 6,000 or more credits generated…" ARB Staff did not give a reason as why deferred verification only applies to liquid fuels. LADWP recommends that the deferred verification provision be applicable to NGV (CNG) fueling as well. Alternatively, as mentioned previously, CNG fuel pathway should be exempt from verification if the quantity of fuel produced and reported by any entity does not result in more than 2,000 credits generated in LRT-CBTS during the prior calendar year. (LADWP2_FF10-8)

Comment: Verification of calculations for electricity derived LCFS credits should be exempt for a declared period of time. The exemption for electric vehicles and equipment for third party verification is currently only said to last until CARB has trained the verifiers; this period of time was not specified. Given the relatively low volume of electricity-derived LCFS credits, verification should be exempt for a stated amount of time, or at least a period of 5 years to allow this segment of the market to mature without fleet owners being concerned about paying third-party verification costs with little notice or time to budget. Further, after that period of time projects that fall under a threshold of credits (perhaps 6,000 which is the proposed threshold for verification in fuel transactions) should be exempt indefinitely from third-party verifications. Making this exemption and the timetable for verification exemption clear in the revised Rule would help ease concerns of Port fleet owners and help them budget for electric equipment and LCFS program costs. (POLB1_FF6-7)

Agency Response: Please see Response O-6.3 in Chapter IV that provides staff's reasons for not exempting CNG from verification and staff's reasons for including CNG in the eligibility criteria for deferred verification during a 15-day change.

O-5. ***Fuel Pathway Allocation Accounting for Alternative Liquid Fuels: Commingling and Preventing Double Counting***

Comment: The proposed regulation order is complemented by new CI calculators which simplify the CI calculations for all the common pathways. The regulation

continues to recognize pathways with multiple commingled feedstocks and products. For example, renewable diesel produced from a combination of tallow, used cooking oil and soy oil. Or, co-production of starch and cellulosic ethanol from the same corn feedstock.

The calculators are also meant to be a supporting tool which would make the verification phase easier for fuel producers. The calculators use the aggregate of all the months included in the input data to calculate the CI of any given pathway(s). However, it is not clear that what will be the range of period over which the data will be aggregated for verification purposes. This range of period is critical in regards with the commingling management of the feedstock/products utilized/produced at the facility. For any facility producing commingled products under multiple pathways, there will be a conceptual independence between the different varieties of products sold as entered on the LRT and their respective physical amounts produced. Closing this gap over a given period will be one of the objectives of the verification process.

This implies that, over a given period, the producer must ensure that they have sold the same amounts of the various products they have sold accurately matches the production after considering the inventory changes. Another objective of verification should be to make sure that the balance of the quantities of products produced and sold do not lead to a negative volume of any of the product at the end of the given period.

Moreover, the expectations of the balance closing should be limited to the beginning and the end of the period. The producer shouldn't be forced to demonstrate all the numbers lining up within that period as it leads to excessive costs in terms of collection and extraction of data, running data quality checks and organizing physical records of thousands of individual transactions (like daily production reports or bills of lading).

Therefore, we encourage that ARB should perform this balance check for commingled accounting specifically on a quarterly basis. Subjecting the producers to within-the-quarter accounting check will put undue pressure on their planning and operations. With a quarterly balance check, the verification program will be consistent with the LCFS reporting schedule and will allow the producers to be less susceptible to unexpected operational fluctuations. If calculators are the tool are supposed to assist the accounting during verification, such a period should also be clearly specified either directly in the calculators or their instruction manual. (LCA6_FF68-1)

> **Agency Response:** Please see Response O-7 in Chapter IV regarding commingling and preventing double counting in fuel pathway allocation accounting for alternative fuels.

P. Alternative Diesel Fuel Regulation

P-1. Multiple Comments: *Support for the Proposed Sunset Provisions*

Comment: REG strongly supports recommendations for "bifurcation" of the on road and off road diesel fleet. Staff have worked extensively with numerous stakeholders, including CIOMA, to develop this proposal. We believe it is fair, economical and above all practical and efficient in meeting NOx emissions requirements. (REG3_FF44-42)

Comment: We are pleased to see the amendments regarding bifurcation of the on- and off-road diesel markets in the Alternative Diesel Fuel regulation. We believe these changes are in the best interest of the state's carbon reduction and public health goals. (NBBCABA3_FF4-1)

> **Agency Response:** Staff appreciates the support for bifurcating the ADF sunset provision.

P-2. *Sunset Provision Timeline*

Comment: What is CARB's best estimate for when the sunset provisions for on and off-road will occur? What is the underpinning behind these estimates. (CAF2_FF2-6)

> **Agency Response:** Based on the staff's analysis of the fleet turnover projected by CARB's emissions inventory, the sunset of the in-use requirements for on-road application is anticipated to occur around year 2023 when the vehicle miles travelled (VMT) by on-road new technology diesel engine (NTDE) heavy-duty vehicles in California reaches 90 percent of total VMT by the California on-road heavy-duty diesel vehicle fleet. The sunset of the in-use requirements for off-road applications would likely occur after year 2030 when the hours of operation of heavy-duty off-road diesel NTDEs in California reaches 90 percent of the total hours of operation of the California heavy-duty off-road diesel engine fleet. These dates are an estimate based on internal modeling efforts.

P-3. *Bifurcation of Sunset Provisions*

P-3.1. Comment: Why is CARB considering bifurcation and how will any off-road ADF backsliding be prevented? (CAF2_FF2-2)

> **Agency Response:** Staff bifurcated the sunset provisions for on- and off-road sectors to reflect the differences in the anticipated adoption rate of NTDEs in the on- and off-road sectors.
>
> Off-road vehicles and equipment can use red-dye diesel and avoid fuel taxes. The cost differential between fuel taxes and NOx mitigant is expected to be a sufficient deterrent to using un-mitigated on-road biodiesel in off-road equipment. Staff coordinates with the California Department of Tax and Fee Administration and will monitor fuel tax data for biodiesel in on- and off-road applications. If

these data indicate potential issues with the sunset provision design, CARB will take appropriate action.

P-3.2. Comment: Will CARB add language to the ADF which would define transition steps that must occur between on-road sunset and off-road continuity, ensuring BXX+ blends can reach the off-road market and if not, a sunset could not occur?

- For example, blending infrastructure must be sufficient and in place to ensure that off-road BXX+ does not become a stranded fuel especially in high off-road use areas? (note: establishing such a step may in fact accelerate the advancement of overall biodiesel use). (CAF2_FF2-3)

  Agency Response: Staff does not plan to add language to the ADF which would define transition steps that must occur between on-road sunset and off-road continuity. All biodiesel blends above the pollutant control level must be NOx mitigated until the on-road biodiesel in-use requirements sunset, at which point only off-road biodiesel would be subject to the in-use requirements. Fuel suppliers would be responsible for transitioning fuel type.

P-3.3. Comment: We believe that all things considered, bifurcation is not prudent or in the best interest of the pubic at this time – the risk is more than the reward. There are just too many unknowns and the better decision would be to readdress bifurcation once more progress is made with the ADF. By abstaining from bifurcation, CARB can send a clear message to the marketplace that BXX+ infrastructure must be advanced prior to further bifurcation consideration. (CAF2_FF2-9)

Agency Response: Based on the staff analysis, bifurcation ensures appropriate NOx mitigation by addressing potential NOx emissions from the off-road use of biodiesel beyond 2023, while not unnecessarily requiring mitigation for on-road biodiesel.

P-4. ***Emissions Inventory Database Tools***

Comment: "The portion of VMT by on-road diesel vehicles in California represented by NTDEs will be determined using <u>the most current CARB mobile source emission inventory and related tools."</u>

- Are the EmFac reports being abandoned for another "tool"? If so, why?
- Can CARB provide more specificity regarding the "most current CARB mobile source emission inventory and related tools"?
  - What is that "tool" today and could that tool change in the future? (CAF2_FF2-4)

  Agency Response: EmFac is still being utilized as a tool to determine VMT for the on-road diesel engines. Staff uses other emissions inventory tools in addition to EmFac, as appropriate, such as OFFROAD2017 – ORION web database (https://www.arb.ca.gov/msei/ordiesel.htm), to better estimate fuel consumption

for both on- and off-road applications, as well as CEPAM 2016 SIP emissions inventory database (https://www.arb.ca.gov/app/emsinv/fcemssumcat/fcemssumcat2016.php) to further confirm and reconcile data.

P-5. Vehicle Miles Traveled and New Technology Diesel Engines Projection

P-5.1. Comment: Can CARB provide the tool's historical perspective on VMT and NTDE's? (CAF2_FF2-5)

Agency Response: The EmFac emissions model is one of the tools used by CARB to assess emissions from vehicles in California. It is generally revised and updated every three years to better represent CARB's current understanding of motor vehicle travel activities and their associated emission levels. Historically, EmFac has been used to support CARB's regulatory and air quality planning efforts. Additional tools such as the ORION web database and the CEPAM 2016 SIP emission inventory database provide additional supporting data to further complete the emissions analysis.

Staff accessed EmFac (2014) to estimate the NOx emissions and VMT from on-road vehicles to project the sunset timeframe of the biodiesel in-use requirements. Based on staff's analysis, EmFac (2014) projected the VMT by on-road NTDEs to make up about 50 percent of the total on-road VMT in 2016, 78 percent in 2021, and 92 percent in 2023. The sunset of the on-road in-use requirements is projected to occur around 2023.

P-5.2 Comment: Will CARB be providing regular VMT and NTDE update regarding progress towards the on and off-road sunset provisions? (CAF2_FF2-7)

Agency Response: Staff will monitor progress towards meeting the on-road and off-road sunset criteria and will provide public VMT and NTDE updates regarding progress towards the sunset criteria by the end of 2021 and annually thereafter to better project the sunset timeline. The ADF regulation also includes an In Use Requirement Program Review that will be conducted on or before December 31, 2019. In conducting the program review, staff will consider the effects of offsetting factors, in addition to any other factors that may affect NOx emissions stemming from biodiesel use in motor vehicles, including VMT and NTDE adoption.

P-6. *Bifurcating Sunset Provisions and LCFS's Carbon Intensity Reduction Goals*

Comment: How will bifurcation help meet the LCFS's carbon intensity reduction goals? (CAF2_FF2-1)

Agency Response: The primary goal of bifurcating the sunset provisions is to address NOx emissions from the on- and off-road applications appropriately, recognizing the different market trends. However, the use of higher blends of

biodiesel up to B20 may increase once the in-use requirements for on-road application sunset as the cost of these fuels should decrease without mitigation. This may result in increased use of the biodiesel (B100) overall, and therefore, result in more fuels available to meet the LCFS CI reduction goals.

P-7. *NOx Mitigation Cost*

Comment: A final comment about NOx Mitigation. Treat costs have been significantly reduced with the approval of more cost-effective NOx Mitigants. CARB estimated NOx Mitigant biodiesel treat costs would be $0.10/gal (Staff report 10/23/13); those estimates proved conservative – treat costs are better than forecasted. LCFS credit values are more than supporting this incremental cost. (CAF2_FF2-8)

Agency Response: Staff acknowledges that NOx mitigation methods may be available at a lower cost than initially forecasted, although it is unclear whether the commenter's claimed costs include infrastructure costs.

Q. Voluntary NOx Remediation Measure Funding and Draft Supplemental Disclosure Discussion of Oxides of Nitrogen Potentially Caused by the Low Carbon Fuel Standard Regulation

No comments were received on this topic during the 1st 15-day comment period.

R. Economic Analysis

R-1. *Comments Related to the Standardized Regulatory Impact Assessment*

R-1.1. Multiple Comments: *SRIA Needs to be Revised to Include the Impact of Including the ZEV Infrastructure Credit Pathways*

Comment: Part III, Section E, in turn, explains that the Standardized Regulatory Impact Assessment ("SRIA") prepared under Section 11346.3 of the Government Code should be revised to address the dilution of credits and credit values caused by the issuance of credits for unused capacity at hydrogen and DC fast charging stations. (GROWTHENERGY2_FF56-9)

Comment: E. The SRIA Should Be Augmented to Address Impacts Associated with The Proposed Modifications' Dilution of the Value of Credits

The APA requires that state agencies proposing to "adopt, amend, or repeal any administrative regulation" must perform an assessment of "the potential for adverse economic impact on California business enterprises and individuals." (Govt. Code, § 11346.3, subd. (a).) The APA requires, *inter alia*, that CARB prepare a SRIA analyzing "the potential adverse economic impact on California business and individuals of a proposed regulation," (Govt. Code, § 11346.3), and declare in the notice of proposed action any initial determination that the action will not have a significant statewide adverse economic impact directly affecting business. (Govt. Code, § 11346.5, subd. (a)(8); *WSPA v. Board of Equalization* (2013) 57 Cal.4th 401, 428.)

The SRIA should be revised to include impacts associated with the Proposed Modifications. Specifically, the economic impact of providing credits for unused fuel capacity at hydrogen and DC fast charge stations must be considered. As noted by Growth Energy's experts, using a very conservative (*e.g.*, low) assumed value of $100 per LCFS credit, the value of LCFS credits awarded for unused capacity at hydrogen and DC fast charge could amount to as much as $82 million in a single year (2020), and the cumulative value of all credits awarded over period allowed under the Proposed Amendments by CARB is likely to much greater. Further, by providing credits for unused infrastructure, the Proposed Amendments "will decrease the value of LCFS credits generated by other means that do in fact result in actual reductions in GHG emissions." (Exhibit "B" at 2.) This is because "the 'capacity' credit provisions will artificially increase the supply of LCFS credits for which there is a finite demand which in turn will decrease the value of all LCFS credits" relative to what it would have otherwise been. (*Id.*) This devaluing of credits will impact credit holders, and decrease the alleged benefits identified in the Proposed Amendments.

To avoid these impacts, the Proposed Modifications should not be adopted. But if they are, CARB should first revise the SRIA and accurately assess the economic impacts of the Proposed Modifications. (GROWTHENERGY2_FF56-30)

Agency Response: The comment does not request any change to the Proposed Amendments, and since the Standardized Regulatory Impact Assessment for the Proposed Amendments complies with the APA and with Department of Finance requirements, no further response is needed. The SRIA is required to estimate the costs of the proposed amendments; it is not designed to forecast a maximum economic benefit for specific program participants as suggested by the commenter.

In the interest of comprehensive public disclosure, cooperative policymaking, and consistent with state law, requirements, and procedure, staff did perform the sort of updated economic assessment commenter is concerned might have been a critical omission. As part of the rulemaking process, staff updated all Illustrative Compliance Scenarios accounting for estimates of the projected influence of modifications to the original proposal, and completed and submitted a final Form 399, which contains a revised estimate of the economic impact of the proposed amendments, including provisions added or modified in the period between publishing the ISOR and publishing the FSOR as well as revisions due to improved data and information, some which were provided as part of the public comment process. The revised economic estimates indicate that the proposed amendments will likely have a smaller adverse economic cost effect on consumers, mainly due to the new estimate of lower LCFS credit prices, some of which is the result of the addition of the ZEV infrastructure pathways.

With the completion of Form 399 and its submittal, CARB has fulfilled its legal obligation to provide an economic analysis of the finalized proposed amendments.

R-1.2. ***SRIA does not Meet Applicable Standards Under the APA***

Comment: The current SRIA does not meet the applicable standards under the APA. The ISOR's discussion of the "elimination of existing businesses" and "the competitive . . . disadvantages" does not fully address or take into account that the LCFS regulation is projected to increase the price of gasoline. (GROWTHENERGY2_FF56-48)

Agency Response: Please see Response R-1.1 in Chapter IV.

R-2. ***Related to the ISOR Economic Analysis***

Comment: Just as the EA has not been revised to address the environmental impacts of "capacity" credit provisions, the economic analysis presented in the ISOR has not been modified to account for the decreases in LCFS credit prices resulting from capacity credits and the associated economic impacts on low CI fuel producers. (GROWTHENERGY2_FF56-66a)

Agency Response: Please see Response R-1.1 in this chapter.

S. Environmental Analysis

S-1. Multiple Comments: *Comments on the Draft Environmental Analysis*

Comments: CAF2_FF2-0, NBBCABA3_FF4-9, NBBCABA3_FF4-11, FHR2_FF9-1, FHR2_FF9-7, UNICA3_FF38-2, CRF2_FF42-2, GROWTHENERGY2_FF56-6, GROWTHENERGY2_FF56-23, GROWTHENERGY2_FF56-24, GROWTHENERGY2_FF56-25, GROWTHENERGY2_FF56-26, GROWTHENERGY2_FF56-27, GROWTHENERGY2_FF56-28, GROWTHENERGY2_FF56-29, GROWTHENERGY2_FF56-31, GROWTHENERGY2_FF56-32, GROWTHENERGY2_FF56-50, GROWTHENERGY2_FF56-51, GROWTHENERGY2_FF56-52, GROWTHENERGY2_FF56-53, GROWTHENERGY2_FF56-65, GROWTHENERGY2_FF56-67

> **Agency Response:** The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

T. Fuel Neutrality

T-1. Multiple Comments: *Fuel Neutrality*

Comment: Growth Energy strongly believes corn ethanol can help CARB in meeting its greenhouse gas reduction targets; however, the regulations CARB considers should be objective in nature and not favor one industry or technology over another. In this regard, the Proposed Modifications exacerbate the existing shortcomings of the LCFS and ADF regulations. (GROWTHENERGY2_FF56-55a)

Comment: Lastly, the LCFS program was designed to be fuel-neutral and to promote the use of alternatives to diesel and gasoline. Those fuels only make up 20% of the fuel used in California's transportation sector, so we must continue to support all low carbon fuels in order to meet our ambitious goals and provide the air quality that we all deserve. (CNGVC3_FF59-5)

Agency Response: Please see Response T-2 in Chapter IV.

T-2. Multiple Comments: *Smart Charging and Fuel Neutrality*

Comment: however, we view key qualification criteria associated with HRI pathway crediting combined with the new Smart Electrolysis Investment Credit as a deviation from CARB's position on neutrality towards hydrogen fuel supply pathways. (AP1_FF16-2)

Comment: Additionally, the newly proposed Smart Electrolysis Credits does not support CARB's position on neutrality of LCFS fuels and provides favorable treatment to hydrogen production using water electrolysis. Hydrogen produced through smart electrolysis Smart Charging power in LCFS Table 7-2 carries a time weight average power that results in 25% higher carbon intensity to steam methane reforming with renewable attributes (HYB). Considering there are normally incremental costs but no incremental credits available for steam methane reforming production using renewable natural gas or biomethane the Smart Electrolysis Credit subsidy in section 95486.1(e)(2) favors water electrolysis and should be revised.

Another issue identified with smart electrolysis credits in section 95486.1(c)(2)(b) is that smart electrolysis rewards higher power consumption, or lower efficiency hydrogen production. For example, Company A may offer an alkaline water electrolysis system with nominal energy consumption of 50 kWh/kg produced, and Company B may offer a PEM water electrolysis system with nominal energy use of 60 kWh/kg hydrogen produced. Company B that consumes a greater amount of energy will receive a greater amount of LCFS credits. The Smart Electrolysis Credit is rewarding lower efficiency hydrogen production. We suggest this was not the intent of the parties which developed the credits. (AP1_FF16-7)

Agency Response: Staff appreciates the commenter's insight and would like to clarify that the intent of the proposed smart electrolysis pathway is to promote

use of low-CI electricity for producing hydrogen to be used as a transportation fuel. Staff believes, irrespective of the technology used, the proposed pathway would incentivize shifting of electrolytic hydrogen production load to times when marginal emissions of grid electricity are lower.

U. Rulemaking Procedure

U-1. *Peer Review*

Comment: It is unclear whether CARB sought external peer review for:

- The accuracy of each of the components of CA-GREET 3.0, and the effect on the CI for corn ethanol and sugarcane ethanol;
- The ILUC for corn ethanol;
- The EER for electricity;
- The efficacy of NTDEs to reduce NOx emissions from biodiesel;
- The accuracy of CARB's compliance scenario, including but not limited to the adaptation of alternative jet fuels, solar steam projects, and renewable diesel; and
- The potential impacts associated with CARB's compliance scenarios, particular with respect to alternative jet fuels, solar steam projects, and renewable diesel. (GROWTHENERGY2_FF56-49)

Agency Response: Please see Response U-3 in Chapter IV, as well as response to GROWTHENERGY1_B4-17 in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

U-2. *Requirements of Transparency*

Comment: CARB must maintain a full and complete rulemaking file:

- The rulemaking file must include external communications submitted to the staff, the Executive Officer or the Board prior to the date when the rulemaking file is formally opened. If those communications are not included, it should be explained why.
- Growth Energy urges CARB to take all necessary measures to ensure all external submittals (not within the scope of section 11347.3(b)(7)) concerning this regulatory process have been included in the rulemaking file.
- Growth Energy also urges CARB to ensure all factual information relied upon by CARB staff in connection with the consideration of the Proposed Amendments is included in the rulemaking file. (GROWTHENERGY2_FF56-54)

Agency Response: Please see Response U-4 in Chapter IV, and response to GROWTHENERGY1_B4-16 Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

V. Analysis of Alternatives

V-1. Multiple Comments: *E15 and Higher Ethanol Blends*

Comment: Part II, Section D explains that, unlike the Proposed Modifications, Growth Energy's E15 Alternative would result in actual reductions of greenhouse gas emissions; thus, CARB should fully evaluate the incorporation of E15 into the LCFS as an alternative. (GROWTHENERGY2_FF56-8)

Comment: Analysis of Alternatives Under the Government Code

…

- CARB should consider the E15 Alternative under which CARB would concurrently adopt fuel specifications for E15 and incorporate E15 into the LCFS. (FF_GROWTHENERGY2_FF56-47)

Comment: Given that CARB is proposing a completely new regulatory element in a 15-day notice[7], it should also be noted that there are alternatives that CARB has failed to consider that would generate substantial additional amounts of LCFS credits tied to real reductions in GHG emissions and the CI of California transportation fuels. One such alternative would be to allow the sale of E15 to be sold in California. Again it is easy to assess the potential GHG reduction benefits from allowing E15 to be sold in California. Using the same example provided above, e.g. CARB's LD/High ZEV/20% scenario for calendar year 2020, and assuming that the credits generated only by starch ethanol increase by 50% (given that the volume of ethanol used will increase by 50% going from E10 to E15), the resulting reduction in GHG emissions would equal 1,126,000 metric tons of GHG emissions from increased use of ethanol plus a further reduction of another 760,000 metric tons of GHG emissions due to reduce use of petroleum based gasoline blendstocks. Again, it is completely unclear why CARB is foregoing the opportunity to generate significant reductions in GHG emissions through allowing the use of E15 while at the same time providing large amounts of LCFS credits to hydrogen and DC fast charging station operators that do not involve a reduction in GHG emissions. Nor has CARB articulated any environmental basis for making these edits in its 15-Day Notice.

[7] CARB refers to "capacity" credits as "unprecedented and novel" and they are discussed nowhere in the Initial Statement of Reasons for the proposed LCFS amendments.

(FF_GROWTHENERGY2_FF56-66c)

Agency Response: Please see Response V-1 in Chapter IV.

V-2. *Western States Petroleum Association Alternative*

Comment: CARB should consider the WSPA Alternative which contemplates that GHG emissions currently attributable to the LCFS program would "instead be achieved by the Assembly Bill (AB) 32 Cap and Trade Program in the most cost-effective manner to address GHG emissions." (GROWTHENERGY2_FF56-46)

Agency Response: Please see Response to GROWTHENERGY1_B4-50 in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

V-3. *Consider Alternatives to the LCFS Regulation*

Comment: As such, CARB should fully address and consider meaningful alternatives to the LCFS regulation (including the WSPA Alternative and the E15 Alternative), and should decline to incorporate the Proposed Modifications into the Proposed Amendments. (GROWTHENERGY2_FF56-55b)

Agency Response: Please see Responses to V-1, and V-2 in Chapter IV, and to GROWTHENERGY1_B4-50 in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

W. Miscellaneous

W-1. Multiple Comments: *Not Within Scope of Rulemaking*

W-1.1. Comment: The State and/or CARB should implement measures allocating funding to develop infrastructure, such as waste processing facilities and biomethane pipelines, that is needed to produce low-CI fuels to comply with the LCFS regulations as well as to meet the organic waste disposal reduction targets of Senate Bill 1383. The availability of such infrastructure is crucial to achieve the 2020 and 2025 organic waste disposal reduction targets of 50 percent and 75 percent, respectively. The 88 cities in Los Angeles County and the County unincorporated communities currently have a maximum organic waste composting and AD processing capacity of approximately 0.5 million tons per year and approximately 1.3 million tons per year of chipping and grinding capacity. Additionally, it is estimated that jurisdictions in Los Angeles County also dispose over 3.5 million tons per year of organic waste. Additional composting and especially AD infrastructure, at an estimated cost of over one billion dollars, is needed to address this capacity shortfall. The Task Force believes that some funding assistance from Cap and Trade should be made available to jurisdictions for the construction and operation of the needed facilities.

This funding for waste processing facilities should not be limited to AD and composting facilities only and should also include non-combustion thermal conversion technologies (CTs). These facilities can produce low-CI fuels and reduce emissions of methane and other GHGs by processing recyclable materials and thus avoid potential landfill disposal of recyclable materials due to China's National Sword Policy. (TASKFORCE2_FF7-5)

> **Agency Response:** Please refer to Response W-4 in Chapter IV and specifically to the response for TASKFORCE1_89-3 in that section.

W-1.2. Comment: Also, very importantly, vehicle use helps advance local air pollution protection by substantially reducing NOx emissions. Due to this environmental benefit of fuels projects, CalBio suggests there be a separate incentive within the CI which tied to fleet conversions from diesel to R-CNG or, down-the-line, to electricity, based on the environmental benefits. This could be analogous to the evaluation in the CI score of a project's use of the fossil versus renewable electricity to produce its fuel. (CALBIO1_FF67-4)

> **Agency Response:** Staff is unclear as to what the commenter is suggesting, but notes that the use of R-CNG-fueled trucks for a transport process that is included in the fuel pathway system boundary (such as for transport of fuel to stations) may be recognized in the CI determination if documentation can be provided and there is reasonable certainty that all, or a quantifiable part, of such transport will be performed with a fleet using R-CNG. Alternatively, if the transport process occurs in California, the dispensing of R-CNG to such a fleet can be reported for credit generation.

W-1.3.Comment: PMSA also recommends that CARB develop an Energy Economy Ratio (EER) values for the use of various sources of LNG as a bunker fuel on vessels. There are an increasing number of vessel orders for dual-fuel capable ships. These ships will be capable of using traditional marine diesel bunkers or liquefied natural gas (LNG) as a fuel. Whether they do or not these future ships use LNG will depend on the availability of LNG fuels and the impact to competitiveness the use of LNG will have. The use of LNG as a marine fuel has the potential to eliminate diesel particulate matter, reduce nitrogen oxide emissions, and, depending on the source, reduce GHG emissions. CARB can encourage the use of low carbon intensity LNG fuels by establishing EER values for variously-sourced LNG used as a marine fuel. Doing so will create a clear signal to the maritime industry. (PMSA1_FF14-3)

> **Agency Response:** Please refer to Response W-4 in Chapter IV and specifically to the response for REG1_88-7 in that section.

W-1.4.*Suggestions for Promoting ZEV on Transportation Network Company Platforms*

Comment: But in order to begin this transformation as soon as possible (which is critical to mitigate CO2 accumulation), governmental intervention is needed because zero-emission vehicles (ZEVs) are not yet at cost-parity with non-ZEVs. In April of 2018, the California Public Utility Commission released a report detailing the opportunities and challenges for Transportation Network Companies ("TNCs", like Lyft and Uber) to expand the number of ZEVs on their platforms. The CPUC found that the cost of ZEVs, including BEVs, was a major barrier to TNC drivers, the majority of whom are considered "low income." According to the CPUC, the median income for a BEV-purchasing household in CA is over $150,000 per year, while the typical TNC driver makes less than ⅓ of this and as a result cannot afford to purchase a BEV. There are other major barriers to TNC BEV proliferation like access to fast charging, DCFC installation and fuel cost, and long-range BEV availability, but for the purposes of this comment, we will focus on the major barrier to making ZEVs affordable and accessible to TNC drivers – the cost premium of ZEVs – by leveraging the LCFS.

We would like to propose that CARB considers modifying the LCFS program to allow owners/operators of high annual mileage vehicles ("High Mileage Fleet Owners") to capture Point of Sale incentives on ZEVs based on the anticipated mileage of its vehicles. For instance, a TNC (or other High Mileage Fleet Owner) may partner with a car rental company to make ZEVs available to its drivers. These ZEVs will travel around 4 times as many miles per year compared to a personal vehicle (e.g. 50K vs. 12K miles per year). If the vehicles are to be in TNC service for 3 years, we suggest that the fleet owner be able to capture the ~150,000 miles worth of LCFS value up front at Point of Sale. Without this PoS incentive, the potential TNC fleet partners we've spoken with are unable to provide ZEVs at competitive price versus gasoline vehicles, and hence are unable to deploy ZEVs into high-mileage fleets.

Notably, the expected value stream of LCFS credits over time, even in a high-mileage application, is not enough for fleet partners to get over the ZEV purchase cost barrier;

only an aggregation of the credit value into a PoS incentive can unlock the ability to scalably deploy ZEVs at scale into high-mileage fleets. A program of this sort could be the fastest way to displace VMT with eVMT on California's roads, and provide the most "environmental bang for buck" of LCFS credit value. In addition, according to the CPUC and our internal data, Lyft drivers tend to be low income and/or minorities, so an additional benefit of such a program would be an economic way for low income and minority drivers to access clean transportation and clean jobs.

The exact mechanism of accounting for and distributing this credit value is open for discussion. One idea would be for companies like Lyft to gather and share data about LCFS credits generated from charging (not captured elsewhere to prevent "double counting") and report this to ARB regularly. This will help set and calibrate the exact PoS incentive. The entity that actually manages the program is up for discussion as well. In one embodiment, the electrical utilities could manage the program (analogously to the potential unmetered residential charging PoS program) and perhaps front-load and monetize the future credits from existing credit streams. Other possible managers could be OEMs, EVSE companies, or some other public or private entity. (LYFT1_FF50-1)

> **Agency Response:** Staff appreciates the commenters' suggestions for supporting expansion of Zero-Emission Vehicles (ZEV) on Transportation Network Companies (TNC) platforms. However, staff would like to note that these recommendations are not within the scope of this rulemaking because the modifications discussed in the comment were not incorporated in the proposed revisions or included in the notice of changes. Staff believes the TNC drivers would still benefit from several other direct and indirect incentives for ZEVs supported by LCFS program, including but not limited to point-of-purchase rebates, development of ZEV refueling infrastructure, and residential and non-residential rate options for EV charging. Additionally, TNC companies, such as the commenter, can develop charging infrastructure and use the proceeds to support the purchase or lease of EVs by their drivers.

W-1.5. Comment: III. Allow transportation network companies (TNCs), which serve the public, to benefit from LCFS crediting by altering access requirements.

Given the critical role that TNCs have in serving the public and increasing public awareness of EVs, we respectfully suggest that DCFCs serving TNC fleets be eligible for the FCI credit. The public benefits from electrification of TNCs, particularly as more and more Californians are choosing to rely on ridesharing and forgo personal vehicle ownership altogether.

As written, the draft rules would disincentivize TNCs from partnering building out ZEV infrastructure, as the LCFS rules only apply to stations open to the public. This restriction comes at a time when proposed legislation (SB104) would require TNCs to electrify. Similarly, ongoing discussions at the CPUC about the environmental

implications of the TNC transformation – notably the TNC "disruption's" effect on greenhouse gas emissions – is creating increased pressure to electrify their fleets.[1]

[1] http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPD_Work_Products_(2014_forward)/Electrifying%20the%20Ride%20Sourcing%20Sector.pdf

Because individual TNC operators often drive upwards of 50,000 miles per year, companies are pursuing dedicated infrastructure for their drivers. The purpose of dedicated infrastructure is to ensure that TNCs can meet their greenhouse gas reduction goals, have charging infrastructure readily available so that drivers can minimize "dead time," and so that drivers may find available charging as quickly as possible so that they may serve their customers. In a CPUC report entitled *Electrifying the Ride-Sourcing Sector in California*, Lyft recently reported that most drivers on its Express Drive program have no access to home charging, which further points to the importance of fast-charging infrastructure to unlock TNC EV usage.

Promoting dedicated TNC fast-charging infrastructure would have many ripple effects that promote electric vehicle use, both within TNCs and in the greater public.

First, TNCs account for an increasing share of California vehicle miles travelled, and access to fast-charging infrastructure is consistently listed as a key barrier to EV TNC deployment. According to the CPUC, "lack of access to fast charging was identified as the most significant barrier to EV use" and drivers with EVs "would have worked an additional 10 hours per week, on average, if they had access to faster and easier charging."

Second, TNC drivers with EVs serve as ideal EV ambassadors to the driving public. While dedicated charging infrastructure is not available to the public, TNC drivers serve the public and make their ride hailing services available to the public. Again referencing the *Electrifying the Ride-Sourcing Sector in California* report, the CPUC writes that exposure to EVs for both the public and TNC drivers "has been found to result in lasting positive impressions that influence subsequent vehicle purchase decisions." Sixty-seven percent of drivers reported that passengers discussed the car's EV technology at least once per work period, suggesting that the TNC sector can serve as a platform to expose passengers to EVs. Therefore, allowing TNCs to unlock LCFS credits would greatly increase TNC EVs on the road, which in turn would spur personal-use drivers to purchase EVs. Even in the case that a passenger does not ultimately purchase an EV, this has the direct GHG reduction benefit of rideshare customers replacing their own personal vehicle miles traveled with EV-powered TNC rides.

Finally, through our experience with our own public network, we have found that dedicated infrastructure for TNCs benefits the public by taking TNC EV drivers off of the public network. TNC drivers' need for frequent charges leads to queuing at stations. This can – and does - negatively impact the public charging experience at these stations. Our customers have told us that their fast-charging experience would be improved if ride-sharing drivers had access to dedicated-charging infrastructure.

Given the goals that California has for electrifying ride share, the service that TNC EV drivers provide to the public, and the necessity for expanded infrastructure dedicated to these drivers, EVgo respectfully requests that CARB staff consider altering public access requirements within the proposed LCFS modifications to unlock opportunities for TNC drivers. (EVGO1_FF62-5)

> **Agency Response:** Staff appreciates the commenter's insights on the benefits and potential barriers for greater adoption of ZEVs for ride sharing applications through Transportation Network Companies (TNC). Staff agrees that there are many benefits associated with electrifying these vehicles and recognizes the service provided to the public by TNCs. The recent signing of SB 1014 does indeed require CARB to establish a California Clean Miles Standard and Incentive Program, which will require a series of actions aimed at reducing vehicular emissions from TNC fleets, including greater adoption of ZEVs. Staff does not think it appropriate to take steps to aid in implementation of SB 1014, as the responsibility will be undertaken by another program within the Agency and has not yet begun.
>
> Staff did not alter the public availability requirements to create an exception for private DC fast chargers providing fuel only to TNC fleets. DC fast chargers owned by TNC fleets would need to meet the public accessibility and payment methods requirements listed in section 95486.2(b). Staff believes that it is less imperative to promote charging infrastructure for fleet applications as the fleet owner can build infrastructure at a pace that is commensurate with the expansion of the fleet. The rapidly expanding public ZEV refueling infrastructure supported by the proposed FCI provisions would be open and available for refueling of ZEVs used for ride sharing purposes.

W-1.6.*Naphtha*

Comment: We request clarification on where renewable naphtha fits on Table 4. (REG3_FF44-10)

> **Agency Response:** Please refer to Response E-3, Energy Density of Renewable Propane and Naphtha, in Chapter IV.

W-1.7.Multiple Comments: *LCFS Implementation*

Comment: Valero proposes a technical correction to Section 95487 – Credit Transactions. Currently, parties are required to report the transfer of credits at the time of physical transfer. The proposed regulations require the transfers to be reported within 10 days of entering into the agreement. To effectively manage and reconcile the data gathered from deal reporting (prompt or delayed) CARB will need a mechanism to tie the physical transfer of credits back to the previously reported deal execution. Valero proposes creating a separate reporting form for Type 2 transfers documenting the agreement for sale or transfer of credits over a termed period and a second credit

transaction form to report the physical transfer of credits which is tied back to the reporting from. (VALERO2_FF11-2, VALERO3_FF27-2)

Comment: Given the changes proposed in this rulemaking cycle to the electricity portion of the LCFS program, ChargePoint recommends that ARB develop a streamlined data collection system. With thousands of chargers currently registered in the program, as well as a proposed Time-of-Use (TOU) program that would require hourly data reporting, the current system of emailing Excel files as back-up verification data is neither secure nor efficient. (CHARGEPOINT3_FF39-7)

Comment: Related to this section, we request allowing credit transfers to be done via Excel and/or XML file like the quarterly fuel transactions to automate the process and reduce errors. (REG3_FF44-19)

Comment: PG&E recommends that ARB clarify in the regulation how the Credit Seller and Credit Buyer should coordinate on initiating and completing the transfer request in the Credit Transfer Form (CTF) provided in the LRT-CBTS, as described in *§95487(b)(1)(C-D)*. In ARB's existing regulation paper, the responsibilities from the Credit Seller to the Credit Buyer are explicit on the handoff between releasing the credit transfer and confirming the credit transfer. While the proposed timing on the transfer and confirmation is going to change in the new regulation, by stating that "the Seller and the Buyer must initiate and complete the transfer request" (Type 1) or "must report the following" (Type 2) leaves confusion and duplicative responsibilities. This could also lead to unnecessary corrections requests which requiring the Executive Officer to review and approve that could be avoided. ARB should provide clear instructions (similar to the existing regulation) on how the responsibilities should transition from Seller to Buyer to complete the transaction.

PG&E also recommends that ARB clarify if there are consequences if there is a deviation from the "date" on all deliveries are anticipated to be completed by both Seller and Buyer (*§95487(b)(1)(D)(5)*). The current LRT-CBTS tool only allows the Seller to "submit" after they have completed the transfer entry. Alternatively ARB could add a "save" functionality in the LRT-CBTS tool that allows the party to go back and update the date of completion during the 10-day entry window, before the entry is formally submitted. (PGE2_FF64-9)

> **Agency Response:** Please see Response W-3, LCFS Implementation, in Chapter IV.

W-2. Multiple Comments: Support for Other Commenters

Comment: Valero supports and incorporates by reference the joint comments submitted by the Western States Petroleum Association on July 5, 2018, to the extent they do not conflict with our position stated herein. (VALERO2_FF11-3)

Comment: Valero supports and incorporates by reference the joint comments submitted by the Western States Petroleum Association and the comments offered by Diamond Alternative

Energy LCC, both on July 5, 2018, to the extent they do not conflict with our position stated herein. (VALERO3_FF27-3)

Comment: The AJF Producers have worked closely and cooperatively with Airlines for American ("A4A") throughout the rulemaking process, and join the separately submitted comments of A4A. (AJFP_FF29-2)

Comment: As members of both the California Advanced Biofuels Association and the National Biodiesel Board (NBB), we wish to align ourselves with the comments they have submitted. (REG3_FF44-1)

Comment: We strongly support The NBB's suggested changes and would reference the agency to their public comments. (REG3_FF44-21b)

> **Agency Response:** Staff acknowledges these stakeholder comments in support of comments provided by other organizations. All comments submitted by the referenced organizations have been responded to elsewhere in the FSOR.

W-3. ***General Concerns***

Comment: To the contrary, we believe several of the proposed amendments could have the unintended consequence of undermining the market for LCFS credits generated by alternative fuels, including renewable natural gas. (RNGC3_FF46-2)

> **Agency Response:** Staff acknowledges the comment's general concern and responds to the specific recommendations elsewhere.

VI. SUMMARY OF COMMENTS MADE DURING THE SECOND 15-DAY COMMENT PERIOD AND AGENCY RESPONSES

Chapter VI of this FSOR contains all comments submitted during the second 15-day comment period with CARB's responses. The second 15-day comment period for additional proposed amendments commenced on August 13, 2018, and ended on August 30, 2018.

CARB received 65 comment letters on the proposed second 15-day amendments during the second 15-day comment period. Table VI-1 below lists the commenters that submitted written comments on the proposed amendments during the second 15-day comment period, identifies the date and form of their comments, and shows the abbreviation assigned to each.

The individually submitted comment letters for the 45-day, first 15-day, and second 15-day comment periods are available here: https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm

Note that some comments were scanned or otherwise electronically transferred, so they may include minor typographical errors or formatting that is not consistent with the originally submitted comments. However, all content reflects the submitted comments. All originally submitted comments are available here: https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm.

Comments that address the draft Environmental Analysis are responded to in the "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuels Regulations."

A. List of Commenters

Listed below are the organizations and individuals that provided comments during the second 15-day comment period:

Table VI-1. List of Commenters During the First 15-Day Comment Period

Comment Letter Code	Commenter
SF_AL2_SF1	David P. Edwards, PhD, Air Liquide Second 15-Day Comment: August 17, 2018
SF_CIG1_SF2	Charles Purshouse, Camco International Group, Inc. Second 15-Day Comment: August 20, 2018
SF_IEAGHG1_SF3	Time Dixon, IEA Greenhouse Gas R&D Programme Second 15-Day Comment: August 22, 2018
SF_SCPPA1_SF4	Tanya DeRivi, Amy C. Mmagu, Nicholas Blair, Southern California Public Power Authority Second 15-Day Comment: August 23, 2018
SF_LCA7_SF5	Stefan Unnasch, Life Cycle Associates, LLC Second 15-Day Comment: August 23, 2018
SF_H2IND3_SF6	David P. Edwards, PhD, Air Liquide

	Dr. Shane Stephens, FirstElement Fuel Stephen Ellis, American Honda Motor Co, Inc. Debbie Bakker, Hyundai Kia America Technical Center, Inc. Nitin Natesan, Linde LLC Matthew Forrest, Mercedes-Benz Research & Development North America, Inc. Mikael Sloth, NEL Hydrogen A/S Wayne Leighty, MBA, PhD, Shell New Energies Michael Lord, Toyota Motor North America Joe Gagliano, United Hydrogen Jeff Serfass, California Hydrogen Business Council Brian Goldstein, Energy Independence Now Second 15-Day Comment: August 24, 2018
SF_H2IND4_SF7	David P. Edwards, PhD, Air Liquide Dr. Shane Stephens, FirstElement Fuel Stephen Ellis, American Honda Motor Co, Inc. Debbie Bakker, Hyundai Kia America Technical Center, Inc. Nitin Natesan, Linde LLC Matthew Forrest, Mercedes-Benz Research & Development North America, Inc. Mikael Sloth, NEL Hydrogen A/S Wayne Leighty, MBA, PhD, Shell New Energies Michael Lord, Toyota Motor North America Joe Gagliano, United Hydrogen Jeff Serfass, California Hydrogen Business Council Brian Goldstein, Energy Independence Now Second 15-Day Comment: August 24, 2018
SF_TASKFORCE3_SF8	Margaret Clark, Low Angeles County Solid Waste Management Committee/Integrated Waste Management Task Force Second 15-Day Comment: August 28, 2018
SF_BONALD1_SF9	Boketsu Banganganda Bonald Second 15-Day Comment: August 29, 2018
SF_CHRISTIANSON2_SF10	Kari Buttenhoff, CPA, Christianson PLLP Second 15-Day Comment: August 29, 2018
SF_CE5_SF11	Todd Campbell, Clean Energy Fuels Corporation Second 15-Day Comment: August 29, 2018
SF_HZI1_SF12	Markus Stangl, Hitachi Zosen Inova U.S.A. LLC Second 15-Day Comment: August 29, 2018
SF_CCSF4_SF13	James Hendry, City and County of San Francisco Second 15-Day Comment: August 29, 2018
SF_CAF3_SF14	Patrick J. McDuff, California Fueling Second 15-Day Comment: August 30, 2018
SF_NSP1_SF15	Tim Lust, National Sorghum Producers Second 15-Day Comment: August 30, 2018

SF_CCAALACVAQ1_SF16	Bill Magavern, Coalition for Clean Air Will Barrett, American Lung Association Dolores Barajas-Weller, Central Valley Air Quality Coalition Second 15-Day Comment: August 30, 2018
SF_CONESTOGA2_SF17	Tom Willis, Conestoga Energy Partners, LLC Second 15-Day Comment: August 30, 2018
SF_AAMGA2_SF18	Julia Rege, Association of Global Automakers, Inc. Steven Douglas, Alliance of Automobile Manufacturers Second 15-Day Comment: August 30, 2018
SF_DTEBE3_SF19	Mark Cousino, DTE Biomass Energy Inc. Second 15-Day Comment: August 30, 2018
SF_WE4_SF20	Kim Do, White Energy, Inc. Second 15-Day Comment: August 30, 2018
SF_OCCIDENTAL5_SF21	Al Collins, Occidental Petroleum Corporation Second 15-Day Comment: August 30, 2018
SF_ECOENGINEERS3_SF22	John Sens, EcoEngineers Second 15-Day Comment: August 30, 2018
SF_IOGEN2_SF23	Patrick J. Foody, Iogen Corporation Second 15-Day Comment: August 30, 2018
SF_SCG4_SF24	Kevin Maggay, SoCalGas Second 15-Day Comment: August 30, 2018
SF_NRWS1_SF25	Tim Dewey-Mattia, Napa Recycling & Waste Services Second 15-Day Comment: August 30, 2018
SF_UCS4_SF26	Jeremy Martin, Ph.D., Union of Concerned Scientists Second 15-Day Comment: August 30, 2018
SF_POLB2_SF27	Heather A. Tomley, Port of Long Beach Second 15-Day Comment: August 30, 2018
SF_CNGVC4_SF28	Thomas Lawson, California Natural Gas Vehicle Coalition Second 15-Day Comment: August 30, 2018
SF_WSPA7_SF29	Catherine Reheis-Boyd, Western States Petroleum Association Second 15-Day Comment: August 30, 2018
SF_UNICA4_SF30	Elizabeth Farina and Leticia Phillips, Brazilian Sugarcane Industry Association (UNICA) Second 15-Day Comment: August 30, 2018
SF_GROWTHENERGY3_SF31	Chris Bliley, Growth Energy Second 15-Day Comment: August 30, 2018
SF_CHARGEPOINT4_SF32	Amanda Myers, ChargePoint Second 15-Day Comment: August 30, 2018
SF_WSPA8_SF33	Catherine Reheis-Boyd, Western States Petroleum Association Second 15-Day Comment: August 30, 2018
SF_WSPA9_SF34	Catherine Reheis-Boyd, Western States Petroleum Association Second 15-Day Comment: August 30, 2018

SF_BART3_SF35	Thomas W. Solomon, Winston & Strawn on behalf of San Francisco Bay Area Rapid Transit District Second 15-Day Comment: August 30, 2018
SF_DTEER1_SF36	Mark Rigby, DTE Energy Resources Inc. Second 15-Day Comment: August 30, 2018
SF_BFP1_SF37	Joy Alafia, Western Propane Gas Association Peter Drasher, Black Bear Environmental Assets Jason Feldman, Green Era Sustainability Ryan Kenny, Clean Energy Neil Koehler, Pacific Ethanol Thomas Lawson, CA Natural Gas Vehicle Coalition Julia A. Levin, Bioenergy Association of California Norma McDonald, Organic Waste Systems Kelly Sarber, Strategic Management Group Bernard Sheff, Montrose Environmental Group/ES Russ Teall, Biodico Second 15-Day Comment: August 30, 2018
SF_TRANE1_SF38	Don Yochum and Nathalie Shaffer, Trane Energy Services Second 15-Day Comment: August 30, 2018
SF_CASA3_SF39	Greg Kester, California Association of Sanitation Agencies Second 15-Day Comment: August 30, 2018
SF_CATFNRDC2_SF40	Briana Mordick, Natural Resources Defense Council George Peridas, Natural Resources Defense Council L. Bruce Hill, Ph.D., Clean Air Task Force James P. Duffy, Clean Air Task Force Deepika Nagabhushan, Clean Air Task Force Second 15-Day Comment: August 30, 2018
SF_C2ESCATFEDFNRDC1_SF41	Jeffrey Bobeck, Center for Climate and Energy Solutions Deepika Nagabhushan, Clean Air Task Force L. Bruce Hill, Ph.D., Clean Air Task Force James P. Duffy, Clean Air Task Force Timothy O'Connor, Environmental Defense Fund Briana Mordick, Natural Resources Defense Council George Peridas, Natural Resources Defense Council Second 15-Day Comment: August 30, 2018
SF_LADWP3_SF42	Nancy H. Sutley, Los Angeles Department of Water & Power Second 15-Day Comment: August 30, 2018
SF_COPERSUCAR1_SF43	Dorothee Luisa Polzer, Copercucar Second 15-Day Comment: August 30, 2018
SF_CALSTART3_SF44	Ryan Schuchard, CALSTART Second 15-Day Comment: August 30, 2018
SF_SREC3_SF45	Steven Eisenberg, SRECTrade, Inc. Second 15-Day Comment: August 30, 2018
SF_CIPA3_SF46	Rock Zierman, California Independent Petroleum Association Second 15-Day Comment: August 30, 2018

SF_EDER1_SF47	Harvey Eder, Public Solar Power Coalition Second 15-Day Comment: August 30, 2018
SF_MACPHERSON1_SF48	Tim Lovley, Macpherson Energy Corporation Second 15-Day Comment: August 30, 2018
SF_PGE3_SF49	Fariya Ali, Pacific Gas and Electric Second 15-Day Comment: August 30, 2018
SF_CALETC4_SF50	Eileen Wenger Tutt, California Electric Transportation Coalition Second 15-Day Comment: August 30, 2018
SF_ENVOY1_SF51	Paul D. Hernandez, Envoy Technologies Inc. Second 15-Day Comment: August 30, 2018
SF_COLTURA2_SF52	Janelle London, Coltura Second 15-Day Comment: August 30, 2018
SF_SCE2_SF53	Michael Backstrom, Southern California Edison Second 15-Day Comment: August 30, 2018
SF_ORGS1_SF54	Mary Solecki, AJW, Inc. Will Barrett, American Lung Association in California Russell Teall, Biodico, Inc. Julia Levin, Bioenergy Association of California Jennifer Case, California Advanced Biodiesel Alliance Carol Lee Rawn, Ceres Nina Kapoor, Coalition for Renewable Natural Gas Timothy J. O'Connor, Environmental Defense Fund Andy Wunder, Environmental Entrepreneurs Shelby Neal, National Biodiesel Board Simon Mui, Natural Resources Defense Council Colin Murphy, NextGen California Neil Koehler, Pacific Ethanol, Inc. Eric Bowen, Renewable Energy Group, Inc. Geoff Cooper, Renewable Fuels Association Second 15-Day Comment: August 30, 2018
SF_ENVOY2_SF55	Paul D. Hernandez, Envoy Technologies Inc. Second 15-Day Comment: August 30, 2018
SF_CF2_SF56	John A. Thornton, CleanFuture Second 15-Day Comment: August 30, 2018
SF_FLUX1_SF57	Andrew Krulewitz, Flux Second 15-Day Comment: August 30, 2018
SF_NRWS2_SF58	Tim Dewey-Mattia, Napa Recycling & Waste Services Second 15-Day Comment: August 30, 2018
SF_SMUD3_SF59	Steven G. Lins and Bill Boyce, Sacramento Municipal Utility District Second 15-Day Comment: August 30, 2018
SF_NEXTGEN4_SF60	Colin Murphy Ph.D., NextGen California Second 15-Day Comment: August 30, 2018
SF_SCAVENGER1_SF61	Douglas Button, South San Francisco Scavenger Company Second 15-Day Comment: August 30, 2018

SF_EDER2_SF62	Harvey Eder, Public Solar Power Coalition Second 15-Day Comment: August 30, 2018
SF_SEVCG4_SF63	Neal Reardon, Sonoma Clean Power Authority on behalf of the Smart EV Charging Coalition Second 15-Day Comment: August 30, 2018
SF_CPUC1_SF64	Michael Picker and Carla Peterman, California Public Utilities Commission Second 15-Day Comment: August 30, 2018
SF_REG4_SF65	Scott R. Hedderich, Renewable Energy Group, Inc. Second 15-Day Comment: August 30, 2018

B. General Comments in Support of the Proposed Amendments

B-1. Multiple Comments: *General Support for the Proposed Amendments*

Comment: HZI strongly supports California's greenhouse gas (GHG) emission reduction goals and believes that a well-designed LCFS program that incentivizes clean and low-carbon fuels will play a key role in achieving California's GHG emission reduction targets and many co-benefit goals including reductions in oxides of nitrogen (NOx) and particulate matter (PM).

…

HZI supports the LCFS as a program that helps meet California's deep GHG emission reduction targets while spurring investment in clean, low carbon transportation fuels. (HZI1_SF12-1)

Comment: We strongly support amending the LCFS with higher percentages, inclusion of alternative jet fuels, updated carbon intensity values and energy efficiency ratios for freight and transit, and a point-of-purchase incentive program for zero-emission vehicles. The LCFS is already helping to reduce greenhouse gas emissions and air pollution by starting the process of diversifying our transportation fuel mix, and needs to be ramped up to maximize progress toward that goal. The LCFS increases the use of alternative vehicle fuels like electricity, hydrogen, renewable diesel and renewable methane, reducing our reliance on petroleum and spurring greater transition to zero emission transportation solutions. The LCFS is playing a critical role in supporting the transition of transit buses, fork lifts and other vehicles to electric drive technologies. (CCAALACVAQ1_SF16-2)

Comment: We continue to support CARB's effort in strengthening the LCFS program to ensure its long-term sustainability and generally support the current LCFS proposed amendments. (CONESTOGA2_SF17-1)

Comment: On behalf of our more than 75,000 supporters in California, the Union of Concerned Scientists strongly supports the 2018 Low Carbon Fuel Standard (LCFS) amendments proposed in the Initial Statement of Reasons. We were pleased that the Board resolved in April to advance the process of finalizing these amendments.

…

Notwithstanding our concern, we support the Board finalizing the LCFS amendments as presented. (UCS4_SF26-1)

Comment: BART appreciates CARB's second 15-day modifications to the proposed new LCFS Regulation, noticed on August 13, 2018, which make several clarifying changes requested by BART in its prior comment letters. (BART3_SF35-1)

Comment: Again, BART fully supports CARB's goal of reducing California's GHG emissions, and to this end appreciates CARB's efforts to continue to improve the LCFS Regulation. (BART3_SF35-4)

Comment: LADWP reaffirms its strong support of the LCFS program and its role in achieving the substantial greenhouse gas (GHG) emissions reductions goals of Assembly Bill (AB) 32 and Senate Bill (SB) 32. (LADWP3_SF42-1)

Comment: We continue to enthusiastically support the LCFS, which is one of California's most effective policies for driving down greenhouse gas (GHG) emissions from transportation while accelerating the commercialization of advanced clean technologies.

We applaud the Board and staff for its commitment and hard work to refining the program as the market evolves. (CALSTART3_SF44-1)

Comment: PG&E continues to strongly support California's greenhouse gas (GHG) emission reduction goals as established in Assembly Bill 32 and Senate Bill 32. Maintaining a well-designed LCFS program that advances low-carbon fuels will play a key role in achieving the state's 2030 GHG emissions reduction targets. We believe that the increased use of electricity, natural gas, and hydrogen as transportation fuels is critical for the success of the LCFS program.

…

PG&E continues to support the Low Carbon Fuel Standard as a program that will help the state meet its aggressive climate goals while maintaining a healthy economy, and appreciates the opportunity to comment on these amendments. (PGE3_SF49-1)

Comment: CalETC supports the LCFS, a program that has been successful thus far in reducing the carbon intensity of California's transportation fuel. Given the near-total dependence on oil in the transportation fuels sector, the LCFS is essential to both diversify the transportation fuels sector and reduce emissions from carbon-based fuels. (CALETC4_SF50-2)

Comment: SCE has long supported the LCFS regulation and its goals of diversifying the fuel supply and reducing the carbon intensity of California's transportation fuel. We believe the utilities are uniquely positioned to play an important role in these goals and in the LCFS regulation.

SCE supports the proposed modifications in the second round of 15-day changes to the LCFS regulation and appreciates the tremendous effort of the CARB staff to improve the regulation after the April Board hearing and respond to stakeholder comments in this period. (SCE2_SF53-1)

Comment: Envoy appreciates the opportunity to provide these comments. Envoy stands in strong support of CARB's leadership on LCFS matters and requests the consideration of our proposed revisions. (ENVOY2_SF55-8)

Comment: CleanFuture strongly supports the LCFS and CARB's efforts to encourage the use and production of cleaner low-carbon fuels. (CF2_SF56-1)

Comment: SMUD is supportive of staff's suggested modifications and continues to implement innovative programs to move the economy of the Sacramento region toward a zero-emission transportation future. (SMUD3_SF59-1)

Comment: NextGen strongly supports the re-adoption of the Low Carbon Fuel Standard through 2030. With one notable exception, we support the current proposal, which reflects months of analysis, consultation and collaborative work among stakeholders. (NEXTGEN4_SF60-1)

Comment: CARB has an opportunity to build upon many years of success by extending a strong LCFS program through 2030 and building upon the foundation it has laid. California has an opportunity to continue its leadership in climate, clean energy and transportation policy for years to come. (NEXTGEN4_SF60-19)

Comment: Again, I want to reiterate Scavenger's support for the LCFS program and how it is helping improve the transportation emissions in California; (SCAVENGER1_SF61-2)

Comment: The Smart EV Charging Group continues to support the California Air Resources Board ("ARB") staff's initiative and foresight in developing proposed LCFS amendment language that would encourage the expanded use of low carbon resources in electrifying the state's transportation networks. (SEVCG4_SF63-1)

Comment: The CPUC supports California Air Resources Board's (CARB) goals to streamline alternative vehicle funding and programs so that they are successful for customers and largely is in favor of the proposed second 15-day modifications to the LCFS regulation. (CPUC1_SF64-1)

> **Agency Response:** Staff appreciates the commenters' support for the LCFS and the proposed amendments and the specific modifications to the proposed amendments described in the comments above.

B-2. Multiple Comments: *Take Action This Year*

Comment: We hope ARB moves forward with swift adoption of these proposed changes. (NSP1_SF15-5)

Comment: On behalf of the undersigned organizations, we write to encourage the California Air Resources Board to move forward with the adoption of the 2030 Low Carbon Fuel Standard as an important component of achieving California's clean air and climate standards. The LCFS is a core program addressing the many harms caused by the transportation fuels sector, and spurring the transition away from combustion of fossil fuels. The LCFS provides leadership on this critical issue, protects public health and our environment while spurring innovation and modeling successful climate policy. (CCAALACVAQ1_SF16-1)

Comment: We urge CARB to take action in September to implement these recommendations to ensure a successful implementation of the point-of-purchase EV rebate program. California has set bold targets for EV adoption, low carbon fuel use and air quality improvements. It will take smart, focused policy to ensure these targets are achieved. The recommendations in this letter represent a significant step in that direction. (COLTURA2_SF52-5)

> **Agency Response:** Staff appreciates the commenters' support for the agency's efforts to complete the rulemaking this year to implement these changes. Staff also appreciates the specific recommendations associated with these comments, which are responded to elsewhere.

C. Definitions

C-1. Multiple Comments: *Support for the Modifications to Definitions*

Comment: Iogen also supports the proposed changes to the definition of "biomethane", which now includes biomethane used for the production of renewable hydrogen. (IOGEN2_SF23-2)

Comment: REG supports the updated definitions of Animal Fat/Yellow Grease and Renewable Propane… (REG4_SF65-1)

> **Agency Response:** Staff appreciates the commenters' support for the amended definitions.

C-2. *Definition of Fuels*

C-2.1. *Biomass-based Diesel*

Comment: In § 95481(a)(19), the proposed language should refer to "renewable hydrocarbon diesel" rather than "renewable diesel" to be consistent with the definition in § 95481(a)(123). (WSPA7_SF29-2)

> **Agency Response:** Please see Response C-1.1 in Chapter V.

C-2.2. *Renewable Propane*

Comment: REG supports the updated definitions of … Renewable Propane though we'd recommend changing the acronym from LGP to LPG. (REG4_SF65-2)

> **Agency Response:** Staff appreciates the commenter's support on the updated definitions. Please see Response C-1.2 in Chapter V for the liquefied petroleum gas acronym comment.

C-2.3. *Biomethane*

Comment: Page 9: The current modifications to the amendments propose to expand the definition of "biomethane," also referred to as "renewable natural gas," in Section 95481 of the Health and Safety Code to include synthetic natural gas derived from renewable resources, including the organic portion of municipal solid waste, which has been upgraded to meet standards for injection into a natural gas common carrier pipeline, or for use in natural gas vehicles, natural gas equipment, or production of renewable hydrogen. The previous version of the amendments limited the definition of "biomethane" to meeting pipeline quality natural gas standards online. The Task Force thanks CARB for expanding the definition of "biomethane." However, the Task Force continues to believe that the definition of "biomethane" should not be limited by end use and should include any natural gas derived from renewable resources regardless of its end use. (TASKFORCE3_SF8-1)

Agency Response: Staff appreciates the commenter's support for the amended definition. Staff recognizes that there are contexts in which additional end uses exist for biomethane; however, the definitions in section 95481(a) are applicable only to the LCFS regulation (sections 95480 through 95503) and, for the purpose of the LCFS regulation, staff seeks only to provide sufficient information to clarify how a fuel pathway can be certified and reported to the LCFS. Furthermore, staff believes that the end uses listed in the definition provide clarity on the uses of biomethane that may be recognized under the LCFS and are sufficiently general so as to not be functionally limiting.

C-2.4. *Hydrogen*

Comment: Section 95481(a)(124) "Renewable Hydrogen" means hydrogen derived from (1) electrolysis of water or aqueous solutions using renewable electricity; (2) catalytic cracking or steam methane reforming of biomethane; or (3) thermochemical conversion of biomass, including the organic portion of municipal solid waste (MSW). Renewable electricity, for the purpose of renewable hydrogen production by electrolysis ***or for hydrogen compression, liquefaction, distribution or dispensing,*** means electricity derived from sources that qualify as eligible renewable energy resources as defined in California Public Utilities Code sections 399.11-399.36. (AL2_SF1-3)

Agency Response: Staff did not propose any changes based on the commenter's recommended as that is not necessary for the definition "Renewable Hydrogen." With regards to the use of renewable electricity for hydrogen compression, liquefaction, distribution or dispensing, please see Response D-6.8 in this chapter addressing comment AL2_SF1-4.

D. Fuels Subject to the Regulation

D-1. *Alternative Jet Fuel*

D-1.1. *Support for the Inclusion of Alternative Jet Fuel in the Low Carbon Fuel Standard*

Comment: We support the inclusion of alternative jet fuels in the LCFS as a way to address this significant and growing source of GHG emissions. Reducing emissions from aviation has been difficult, and inclusion in the LCFS will help to shift jet fuels toward more sustainable alternatives to petroleum. (CCAALACVAQ1_SF16-4)

> **Agency Response:** Staff appreciates the support for including alternative jet fuel in the LCFS program as an opt-in credit-generating fuel.

D-1.2. *Default Energy Density for Alternative Jet Fuel*

Comment: We advise CARB to reconsider setting a default energy density for alternative jet fuel. There are several potential chemical routes to produce this fuel which may result in fuels with different energy densities. Speaking from the prospective of a renewable diesel producer, fractional distillation is applied at the end of our process to separate out products which may include diesel, naphtha, LPG, and jet fuel. Depending on effectiveness of the separation and the specific setup of the biorefineries, our products may have different energy contents than a different biorefinery which employs the same technology.

EPA recognized this when crafting the RFS, requiring fuels such as renewable naphtha and renewable jet fuel to file equivalency value (EV) applications. These EV applications contain the lower heating value of the RIN generating fuel. We encourage CARB to require companies to use the lower heating value contained in each company's EV application when calculating credits generated for naphtha, alternative jet fuel, and other fuels which energy content may vary from producer to producer. (REG4_SF65-5)

> **Agency Response:** The energy density of alternative jet fuel (synthetic paraffinic kerosene) in CA-GREET3.0 is a user-defined value (yellow cell) and not a default value. In addition, the applicant must consult with staff to develop the energy density (heating value) of the renewable jet fuel in the "Tier 1 Simplified CI Calculator for Biodiesel and Renewable Diesel" if it is one of the co-products in the renewable diesel production process.

D-2. *Propane*

No comments were received on this topic during the 2nd 15-day comment period.

D-3. *Fossil Compressed Natural Gas*

D-3.1. Multiple Comments: *Support for Small Station Exemption*

Comment: Page 33: Page II-6 of the Staff Report proposed to remove the opt-in status of fossil compressed natural gas (CNG). In the previous version of the modified text released in June 2018, Section 95482 of the Health and Safety Code was previously modified to exempt small fossil compressed natural gas (CNG) fueling stations with a total throughput of 50,000 gasoline-gallons equivalent or less per year from LCFS requirements until the respective fuels become deficit generating to allow small station operators to participate in the LCFS. The current version of the modified text increases the throughput limit to 150,000 gasoline-gallons equivalent or less per year.

The biogas market has significant potential to expand over the next few years due to the organic waste disposal reduction mandated by Senate Bill 1383 (Chapter 395 of the 2016 State Statutes) and its implementing regulation, which focuses on anaerobic digestion (AD) technologies and processes to generate biogas and biomethane. Additionally, as monetary incentives for biomethane pipeline infrastructure projects become available pursuant to Assembly Bill 2313 (Chapter 571 of the 2016 State Statutes), it is important that the existing infrastructure for natural gas be properly maintained to provide short-term storage for biomethane and increase access to biomethane for transportation fleets and other end users.

The Task Force thanks CARB for increasing the throughput limit for small fossil CNG fueling stations. However, the Task Force strongly believes that CARB needs to extend the phase-out of all fossil CNG, not limited to small fueling stations, to allow the biogas market to expand to make use of the existing infrastructure and avoid discouraging investments in gas pipeline infrastructure until additional in-state infrastructure is developed to provide for the state's needed renewable CNG. (TASKFORCE3_SF8-3a)

Comment: In previous comment letters, SoCalGas asked for an exemption for small fossil compressed natural gas (fossil CNG) users that have yet to opt in to the LCFS Program. The purpose of an exemption would be to ensure small CNG station operators do not transition back to gasoline or diesel if required to immediately become regulated parties. This will provide industry time to develop products and services for these small CNG station operators that do not have the time or resources to perform additional regulatory tasks and to transition these customers to using renewable natural gas (RNG). You and your staff understood the SoCalGas recommendation and have worked closely with our team to find a solution. The latest changes to the proposed LCFS Amendments includes an exemption for fossil CNG users that use less than 150,000 gasoline gallon equivalent annually. This is a step in the right direction and would help accomplish the goals of an exemption. SoCalGas commends you and your staff on being receptive and open to determining a mutually agreeable exemption threshold. (SCG4_SF24-1a)

Comment: LADWP supports ARB's proposal to increase the threshold for the exemption of small fossil compressed natural gas (CNG) stations to 150,000 gasoline gallon equivalent or less annual throughput from the LCFS until the fuel starts generating deficits. LADWP is a CNG fuel provider primarily for its fleet; the exemption's expiration date of January 1, 2024, for fossil CNG stations will provide LADWP enough time to plan and implement a strategic course of action. (LADWP3_SF42-2)

> **Agency Response:** Staff appreciates the commenters' support for the increased threshold for small stations dispensing 150,000 GGE or less of CNG and LPG to be exempted from mandatory participation until the fuels become deficit-generating.
>
> In response to comment TASKFORCE3_SF8-3a, staff supports and shares the commenter's desire to expand the use of biomethane to displace natural gas used in vehicles, but notes that the characterization of "the phase-out of all fossil CNG" is inaccurate. While the use of fossil CNG in heavy-duty transportation applications will become deficit-generating under the program's 2024 benchmark for diesel substitutes, this does not mean that the use of the fuel will be phased out, nor that any incentive will be phased-out: fossil CNG dispensed to light- and medium-duty vehicles as a gasoline substitute will in fact continue to generate credits through 2030 under the amended regulation.
>
> Moreover, staff estimates that a station dispensing 150,000 gasoline gallon equivalent of fossil CNG to heavy-duty vehicles will earn approximately 285 LCFS credits between 2019 and 2024. At current credit prices this amounts to over $50,000 in value, which should be sufficient value to maintain infrastructure even in the worst case scenario in which the station is dispensing only fossil CNG to only heavy-duty vehicles.
>
> Please also refer to Response D-3.1 in Chapter IV.

D-3.2. ***Exemption and Phase-In Period for Removal of Opt-In Status for Small Station Dispensing Fossil CNG***

Comment: SoCalGas recently conducted a survey of CNG station operators served by both SoCalGas and SDG&E that have not yet opted in to the LCFS Program. Of those interviewed, two-thirds either "never heard of it" or "only heard of" the LCFS program. Since many of these small CNG station operators lack even basic awareness of the LCFS Program, there will likely be an issue with requiring them to become regulated parties by the proposed January 2019 mandatory reporting requirement. When asked why they had not opted in to the LCFS Program to date, a majority of the customers stated they don't have the "resources to commit to it" or the program was "too complicated" or "difficult to understand". Lastly, 80 percent of those interviewed would prefer to enter the LCFS program under a utility-based assistance program to ease the administrative burden and perceived complexity. A two-year implementation delay

would provide time to raise awareness of the program and potentially develop utility-based assistance programs to help users participate.

RECOMMENTATION: While the proposed exemption is a step in the right direction, we also recommend a two-year delayed implementation of mandatory reporting for all fossil CNG users as fossil CNG would not become a deficit generating fuel until 2024. This would ease the administrative burden for users that are already voluntarily using a low carbon fuel and provide a pathway for these customers to begin using RNG. (SCG4_SF24-1b)

Agency Response: Please see Response D-3.2 in Chapter V.

D-4. *Renewable Natural Gas*

D-4.1. *Specified Source Feedstocks*

Comment: Page 296: Page III-137 of the Staff Report designated separated food waste as a "specified source feedstock" subject to additional documentation requirements. On page 254 of the modified text that was released in March 2018, along with the Staff Report, CARB Staff proposed to modify Section 95491.1(a)(2)(F) of the Health and Safety Code to require applicants to maintain a copy of the U.S. EPA RFS Program Separated Food Waste Plan. The Task Force requests that CARB incorporate language into Section 95491.1(a)(2)(F) of the Health and Safety Code to ensure that this additional documentation is consistent with Senate Bill 1383 implementing regulations such that it does not discourage use of separated food waste as a feedstock to produce fuel. (TASKFORCE3_SF8-4)

Agency Response: Please refer to Response E-4.3 in Chapter IV.

D-4.2. *Fuel Production Processes Not Specifically Addressed in the LCFS Regulation*

D-4.2a. Multiple Comments: *Fuel Production Processes Not Specifically Addressed in the LCFS Regulation*

Comment: While we applaud most of the proposed amendments to the LCFS Regulation, we see a lack of recognition for synthetic methane produced from renewable or low carbon electricity. This is an important gap that would prevent this important technology from entering California market and contributing to California's GHG emission reduction and co-benefits targets.

With commercially available compressed natural gas (CNG) engines methane can be 90% cleaner in terms of NOx emissions than diesel when combusted, while offering the benefit of near zero PM emissions. Renewable power-to-methane for CNG vehicles further offers the benefit of deep GHG emission reduction. The methanation process is exothermic; no external heat or electricity is required for the process, and the limited efficiency loss should not be used as a reason to discourage this important technology.

This is especially true, if the hydrogen reactant is produced with renewable or low carbon electricity.

HZI is committed to supplying low carbon hydrogen wherever there is demand. However, when hydrogen demand is not there, we see the immediate GHG and criteria pollutants reduction co-benefits that renewable power-to-methane technology can bring to California and the society, including:

- Renewable penetration in transportation and other hard to electrify sectors, renewable and locally produced transportation fuel, recycling of CO_2, long term energy storage, and clean fuel jobs in local communities.
- The proposed LCFS amendments showed recognition for methane produced from biomass, which HZI strongly supports. However, biomass resources are limited in amount, scale, and location, and probably would be put in best use if used for jet fuels where no viable alternatives are currently available. Methane produced with renewable electricity and anthropogenic CO_2 offers the needed scale, economic and environmental viability in the near term to address the GHG, NOx, and PM issues in heavy duty transportation, and other hard-to-electrify industrial applications. (HZI1_SF12-2)

Comment: With the increase in intermittent renewable energy production, the state has created a scenario where there is over generation of electricity during non-peak hours, when sources such as solar are highest generating. This has resulted in significant generation curtailment, which is expected to grow over time. One potential solution to this is using that excess electricity to create gaseous fuel such as hydrogen to store that energy. When hydrogen is not in demand, the stored hydrogen can be combined with carbon dioxide (CO2) to create low carbon, synthetic renewable natural gas. Companies such as HZI ETOGAS have the experience and capabilities to do these projects having built the largest power-to-methane plant (6.3 MW) in Germany.

Using available technologies to create renewable natural gas from excess renewable energy would reduce the carbon intensity of transportation fuels, help to alleviate stress on the grid caused by over generation issues, and reduce criteria pollutants as new natural gas engine technologies are certified to reduce nitrogen oxide emissions by 90 percent.

RECOMMENDATION: SoCalGas recommends that the LCFS Amendments be modified to explicitly state that synthetic methane produced from renewable or low carbon electricity and CO2 is eligible as an opt-in fuel for credit generation under the LCFS program. (SCG4_SF24-2)

> **Agency Response:** Although the specific technology or fuel production process described by the commenter is not addressed in the regulation, staff does not believe this is a barrier to participation of the fuel under the LCFS. The regulation provides extensive flexibility to evaluate and certify new and innovative pathways under the Tier 2 framework. Pathways for either or both methane and hydrogen produced in the manner described can be submitted, evaluated, and

posted for public comment. Staff also encourages the commenter to apply using the "design-based" pathway process before the required three months of operational data required for a certified Tier 2 pathway is available. This would allow staff to become familiar with the technology, and ensure that CARB and the applicant are aware and in agreement on what specific data and information will need to be provided for a full pathway, before commercial production begins.

D-4.2b. Comment: 1. Renewable natural gas is not clearly defined in the proposed LCFS regulation. The "Biomethane" definition in the regulation does not capture the full range of renewable synthetic natural gas. For example, synthetic natural gas produced from renewable power (via electrolytic H_2) and CO_2 directly captured from air would not fit well within the "biomethane" definition. A more comprehensive definition is needed for renewable natural gas.

…

1. In section "95481. Definitions and Acronyms," add definition "(125) "Renewable natural gas" means natural gas or methane that is produced from non-petroleum renewable resources including biomethane and synthetic natural gas derived from renewable electrolytic hydrogen and renewable CO_2, and meets standards for injection to a natural gas common carrier pipeline, or for use in natural gas vehicles or natural gas equipment." (HZI1_SF12-3)

Agency Response: Staff recognizes that the proposed definitions may not be inclusive of all potential future methods of fuel production; however, as stated in Response D-4.2a in this chapter, staff does believe this is a barrier to participation of the fuel under the LCFS, and will work with the commenter to ensure the relevant and applicable requirements are clear. Through the Tier 2 pathway certification process, the public will also have opportunity to comment on the implementation requirements for such a pathway.

D-4.2.c. Comment: 2. There is a need to make it explicit that synthetic methane produced from renewable or low carbon electricity and anthropogenic CO_2 is eligible as an opt-in fuel for credit generation under LCFS program, the same treatment as that of bio methane.

…

2. In subsection "§95482. Fuels Subject to Regulation. (b) Opt-In Fuels," add provision "§95482.(b)(7) Synthetic methane produced from renewable or low carbon electricity and anthropogenic CO_2." (HZI1_SF12-4)

Agency Response: Staff does not agree with the commenter's suggestion, and believes that the regulation does make clear that the fuel is eligible for participation: section 95482(a) states that "The types of transportation fuels to which the LCFS applies include: …. (13) Any other liquid or non-liquid fuel."

With respect to the opt-in eligibility, an applicant may submit a request to the Executive Officer, and demonstrate that the alternative fuel meets the standard established for other opt-in fuels, namely: that it is not a biomass-based fuel, pursuant to section 95482(c)(1), and that the fuel has a full fuel cycle carbon intensity that meets the compliance schedules set forth in sections 95484(b) and through (d) through December 31, 2030, pursuant to section 95482(b).

D-4.2d. Comment: 3. There is a need to make it explicit that the renewable electricity does not have to be directly supplied for power-to-methane production, and that indirect or book-and-claim accounting is applicable for synthetic methane produced from renewable electricity and anthropogenic CO2 that is used as a transportation fuel, the same treatment as that of bio methane and hydrogen.

…

3. In subsection "§95483. Fuel Reporting Entities. (b) For Gaseous Fuels. (1) Designation of First Fuel Reporting Entities For Gaseous Fuels," add provision "§95483.(b)(1)(F) Synthetic methane produced from renewable or low carbon electricity and anthropogenic CO_2. For synthetic methane produced from renewable or low carbon electricity and anthropogenic CO_2, including its portion of a blend with fossil CNG, the first fuel reporting entity is the producer or importer of the synthetic methane."

…

5. In subsection "§95488.8.(i)(1) Book-and-Claim Accounting for Renewable or Low-CI Electricity Supplied as a Transportation Fuel or Used to Produce Hydrogen. Reporting entities may use indirect accounting mechanisms for ****** (including hydrogen that is used in the production of a transportation fuel)," add a few words to the regulation text as follows: "§95488.8.(i)(1) Book-and-Claim Accounting for Renewable or Low-CI Electricity Supplied as a Transportation Fuel or Used to Produce Hydrogen. Reporting entities may use indirect accounting mechanisms for ****** (including hydrogen that is used in the production of a transportation fuel such as its methane derivative)." (HZI1_SF12-5)

Agency Response: Based on the limited information provided, staff agrees that the proposed fuel could be eligible for the provisions to supply electricity through book-and-claim accounting, analogous to hydrogen produced by electrolysis or from biomethane.

D-4.2e. Comment: 4. There is a need to explicitly make "smart electrolysis carbon intensity (CI) calculation" for hydrogen production an optional "CI calculation step" for the synthetic methane derivative of hydrogen produced from renewable or low carbon electricity.

…

4. In subsection "§95486.1.(f)(2) *Smart Electrolysis Pathways for Hydrogen Production*. An entity can ****** using average grid electricity, for Hydrogen using smart

electrolysis pursuant to section 95488.5 ******," add a few words to the regulation text as follows: "§95486.1.(f)(2) *Smart Electrolysis Pathways for Hydrogen Production*. An entity can ****** using average grid electricity, for Hydrogen (including Hydrogen that is used in the production of its methane derivative) using smart electrolysis pursuant to section 95488.5 ******." (HZI1_SF12-6)

> **Agency Response:** Staff agrees that incremental credits for smart electrolysis could be generated for a pathway that uses hydrogen in the production of another fuel such as methane. Staff does not believe the suggested modification is needed, as nothing in section 95486.1(f) would prohibit the suggested approach.

D-4.3. *Dairy and Swine Manure Crediting – Extend Initial Crediting Period to 20 or 30 Years*

Comment: Section §95488.9(f)(3)(B) states that the passage of "a law, regulation, or legally binding mandate requiring either greenhouse gas emission reductions from manure methane emissions from livestock and dairy projects or diversion of organic material from landfill disposal, comes into effect in California during a project's crediting period, then the project is only eligible to continue to receive LCFS credits for those greenhouse gas emission reductions for the remainder of the project's current crediting period. The project may not request any subsequent crediting periods." It appears to establish additionality requirements for projects and limits a project's crediting period.

We believe that it is in the best interest of the LCFS program to minimize regulatory uncertainty and allow projects that are built the full benefit of the regulations as they are today. The potential for future laws to destabilize project revenues disincentivizes project development.

Recommended Action:

1. Allow registered projects to be grandfathered and claim credits for the three 10-year crediting periods allowed during time of registration if a future law raises the baseline for additionality. (ECOENGINEERS3_SF22-2)

   Agency Response: Please refer to Response D-4.3a in Chapter IV, and D-4.2a in Chapter V.

D-5. *Hydrogen*

No comments were received on this topic during the 2nd 15-day comment period.

D-6. *Electricity*

D-6.1. *Support for the Proposed Modifications to the Electricity Provisions*

D-6.1a. Multiple Comments: Support for Proposed Amendments to the Electricity Provisions

Comment: CalETC supports the proposed second round 15-day modifications to the LCFS draft regulation order including the:

- changes that make more feasible the development of point-of-purchase Clean Fuel Reward[1] (e.g., returning the multi-unit dwelling credits to EDUs);
  [1] Funded with the utilities' base residential credits.
- changes to the California statewide grid average carbon intensity for electricity (especially the delinking in GREET 3.0 the upstream and power plant emissions), the proposed CI and annual update reflect the true benefit of electricity fuel and fairly characterize the CI for electricity;
- many improvements to rules and formulas for the DC fast charging capacity credits
- improved rules for residential charging (base credits and incremental credits) that make it feasible for EDUs to participate; and
- improved requirements on non-load-serving entities (LSEs) so that they must meet requirements similar to those placed on LSEs. (CALETC4_SF50-4)

Comment: The electricity pathway within the LCFS is an important tool to support the Governor's goals of placing more than 1.5 million Zero-Emission Vehicles (ZEVs) on California roads by 2025 and 5 million by 2030. The LCFS amendments before the board provide important updates to the energy efficiency metrics for zero emission trucks and buses, and include credit-generation opportunities for zero emission Transportation Refrigeration Units, cargo-handling equipment and shore power to advance sustainable freight in California. These credits provide an important signal for a broader transition to zero emissions technologies across the transportation fuel sector and should be advanced by the Board. Working together, zero emission LCFS credits, state incentive programs and strong, binding regulations can accelerate the critical transition away from petroleum fuels across the transportation sector. (CCAALACVAQ1_SF16-6)

Comment: San Francisco appreciates the efforts of CARB staff, as reflected in the latest proposed version of the regulation, to address San Francisco's concern that electrified public transit that uses "fixed guideway systems" and is powered by GHG-free, renewable energy receives LCFS credit for its lower carbon intensity. (CCSF4_SF13-1)

Comment: Notwithstanding the recommended changes discussed herein, the Smart EV Charging Group supports the ARB's efforts to facilitate and incentivize greater EV usage and charging through the LCFS program. The Smart EV Charging Group looks

forward to working with the ARB towards the successful rollout of the new EV policies in the LCFS program. (SEVCG4_SF63-8)

> **Agency Response:** Please see Response D.6-1a, Support for Proposed Amendments to the Electricity Provisions, in Chapter IV.

D-6.1b. *Support LCFS for Promoting ZEV Adoption and Transportation Electrification in California*

Comment: The electricity pathway within the LCFS is an important tool to support the Governor's goal of placing 1.5 million Electric Vehicles (EVs) on California roads by 2025 and 5 million by 2030. (COLTURA2_SF52-1)

> **Agency Response:** Please see Response D-6.1j, Support LCFS for Promoting ZEV Adoption and Transportation Electrification in California, in Chapter IV.

D-6.1c. *Support for Proposed Tiers Based on Rated Battery Capacity*

Comment: Our associations and our member companies support the inclusion of a rebate equation to designate the value of the rebate for each PEV. The proposed equation corresponds with the structure of the federal tax credit, which is a well-known and easy-to-implement structure at the manufacturer and dealer level. The equation also recognizes and rewards battery capacity, giving comparable rebates to larger vehicles with lower ranges compared to smaller vehicles with the same battery capacity. This aspect of the rebate designation structure is particularly important as the auto industry works to increase EV offerings in larger vehicles (e.g., minivans, SUVs, etc.). We will work with the utilities and dealers to ensure easy and complete information about the Clean Fuel Reward amounts available to each PEV. (AAMGA2_SF18-7)

> **Agency Response:** Staff appreciates the commenter's support for the proposed tiers for the rebate amount based on rated battery capacity for EVs for a statewide point-of-purchase rebate program.

D-6.1d. Multiple Comments: *Support for Proposed Credit Generator for Multi-Family Residential EV Charging*

Comment: LADWP supports ARB's proposal to keep EDUs as the eligible credit generator for EV charging at multi-family residences. LADWP concurs with ARB's assessment that "EDUs are better suited to receive these credits to help support the point of purchase rebates for electric vehicles and infrastructure development in multi-family residences." As mentioned in LADWP's comment letter of July 3, 2018, the majority of residential customers in LADWP's service territory are renters and live in multi-family residences, and LADWP forecasted that 85-percent of new residential buildings units will be multi-family residences. LADWP has an EV charger rebate, which is funded through residential-based credit proceeds and provides a larger incentive to commercial customers such as multi-family residences. LADWP believes that it is in the best position to provide EV incentives targeted to customers that are

renters in multi-family residences and will continue to support these objectives. (LADWP3_SF42-4)

Comment: PG&E supports keeping the EDUs as the eligible credit generator for EV charging at multi-family residences. Since the EDUs will be using a portion of the revenues from the EV charging residential base credits to fund a statewide point-of-purchase EV rebate program, it is important that multi-family EV charging credits are treated consistently with single-family charging and similarly used to contribute to the statewide rebate program, which will be offered to all Californians in all residence types. PG&E appreciates ARB's reconsideration of this issue and the change to maintain the EDUs as the eligible credit generator. (PGE3_SF49-4)

Comment: *SMUD supports continuation of the Electricity Distribution Utility (EDU) as the credit generator for electric vehicle (EV) charging at multi-family residences. SMUD appreciates the change in the Second 15-day Modifications to treat multi-family residential charging identically to single-family residential charging.*

SMUD supports the second 15-day Modifications to treat credit generation from residential EV charging in multi-family residences identically to single-family residence EV charging. Subdividing residential charging into single and multi-family categories would have added considerable complexity to residential electricity credit generation and reporting. Delineating which EV's are registered at single family residences versus multi-family properties would be problematic given that the definition of "multi-family" residences can be very broad, potentially including duplex housing with individual addresses. Creating a distinction between residential housing types would have resulted in a significant amount of electricity fuel usage being unreported in the market place, inconsistent with the goals of this program. (SMUD3_SF59-2)

> **Agency Response:** Staff appreciates the commenters' support for keeping the utilities as the default credit generator for EV charging at Multi-family residences.
>
> Please also see Response D-6.15a, Proposed Credit Generator for Multi-Family Residential EV Charging, in Chapter IV.

D-6.1e. *Support for Proposed Methodology for Calculating CI Values for Smart Charging Pathway*

Comment: We appreciate the engagement by staff during the development of Smart Charging provisions over this rulemaking process and support the amendments reflected in the current proposal. The current proposal effectively prevents double-counting of renewable energy by prohibiting the same transaction from benefitting from both renewable energy and smart charging incremental credits. As electricity markets evolve and become better able to track the source of electricity on a real-time basis, it may be possible to amend the incremental charging credit provisions to allow simultaneous participation in both renewable and smart charging programs. We look forward to working with CARB and other stakeholders on this issue moving forward.

The smart charging provisions reflected in the current proposal have shifted substantially from the original concept released in March. We recognize the value in aligning the proposed smart charging provision with ongoing work by CAISO and the CPUC to create a standard framework for implementing Time-of-Use (TOU) rates, which offer clear advantages over flat or tiered rates in terms of better aligning utility rates with the real costs, and environmental impacts of electrical generation. We are concerned however, that the proposed system will be extremely complex for consumers who are not aware of how TOU rates function and are not equipped with the information or technological tools to manage their household and vehicular energy demand. We urge CARB to ensure that utilities or charging providers who enroll customers in the smart charging provision educate their customers and provide tools to ensure that EV owners understand the time-based incentives this provision institutes. (NEXTGEN4_SF60-10)

> **Agency Response:** Staff appreciates the commenter's support for the proposed methodology for calculating CI values for smart charging pathway.

D-6.1f. Multiple Comments: ***Support for Proposed Changes to the New Transportation Applications***

Comment: The Port of Long Beach (Port) appreciates the effort that CARB has given to the second set of modifications to the proposed Low Carbon Fuel Standard (LCFS or Rule). We recognize that you have many stakeholders and we appreciate that several of our recommendations were incorporated into the proposed Rule. The Port has set ambitious zero-emissions goals in its Clean Air Action Plan; full participation in the LCFS program will assist in enabling the Port and its terminal and fleet owners to transition away from diesel. The crediting of shore power for Ocean-going Vessels (OGVs) into the LCFS program will encourage ongoing investment in electrical infrastructure and ensure 100% compliance with the at-berth regulation. Further, the Port believes that allowing the owners of the fueling supply equipment (FSE) to generate credits could help properly incentivize the upgrades of diesel equipment, as this type of upgrade, particularly the costly associated infrastructure investments, is significantly less feasible without the added value and benefit of the LCFS credit. The Port also welcomes the inclusion of electric forklifts, Transport Refrigeration Units (TRUs) and other Electric Cargo Handling Equipment (eCHE) into the LCFS program. (POLB2_SF27-1)

Comment: LADWP supports the modifications pertaining to the definition of electric cargo handling equipment and removal of "auxiliary engines" from electric power for ocean-going vessels. These modifications provide clarity to the application of these provisions. These provisions will compliment ongoing efforts taken by LADWP to improve air quality in its service territory, in particular, transportation electrification projects at the Port of Los Angeles. (LADWP3_SF42-5)

Comment: CleanFuture supports the proposed inclusion of electric transport refrigeration units (eTRU), electric cargo handling equipment (eCHE), eOGV, and mechanisms for qualifying other transportation applications not included in Table 5.

These proposed changes will help incentivize and accelerate the transition to lower carbon intensive technologies in the freight and goods movement sector. The amendments released in the First Notice of Public Availability of Modified Text on June 20, 2018 contained provisions for these applications (eTRU, eCHE, EOGV) were positive in incentivizing industry. (CF2_SF56-2a)

Agency Response: Please refer to Response D-6.1i in Chapter V.

D-6.1g. Multiple Comments: ***Support for Proposed Indirect Accounting of Renewable and Low-CI Electricity***

Comment: Notably, the second 15-day modifications added the defined term "Low-Carbon Intensity (Low-CI) Electricity," which would include "any electricity that is determined to have a carbon intensity that is less than the average grid electricity for the region, including but not limited to an 'eligible renewable energy resource' as defined in Public Utilities Code Sections 399.11-399.36 under the California Renewables Portfolio Standard." The definition of "Low-CI Electricity," coupled with changes throughout the regulation to replace references to "renewable energy" with references to "Low-CI Electricity," make it clear that CARB intends for the LCFS to recognize the low-carbon characteristics of Low-CI Electricity. (BART3_SF35-2)

Comment: *SMUD appreciates the clarification in the Second 15-day Modifications that incremental credits can be claimed for low-CI energy procured for existing "green tariff" programs.*

SMUD currently sponsors green pricing programs that meet the definition of a Green Tariff program under the Second 15-day Modifications—SMUD's "Greenergy" program allows customers to purchase up to 100% of their load from Green-e certified renewable energy through a flat monthly fee on their utility bill. We interpret the revisions to sections 95486.1 and 95488.8 to include SMUD's Greenergy program in the definition of eligible zero-CI sources that would generate incremental credits.

Taken together, proposed sections 95486.1(c) and 95488.8(i)(B) direct the Executive Officer to award incremental credits to EDUs for non-metered, residential EV charging by customers on Green Tariff programs such as Greenergy. We interpret this to mean that CARB would issue incremental credits for non-metered residences shown to receive zero-CI electricity based on the same method of estimation used to calculate base credits, and we therefore support this modification. (SMUD3_SF59-3)

Comment: In particular, we appreciate that CARB has considered and incorporated feedback in regard to tracking and retiring any Renewable Energy Credits (RECs) that are used for LCFS credit generation in the Western Renewable Energy Generation Information System (WREGIS). WREGIS is used by electric retail sellers to demonstrate compliance with the Renewables Portfolio Standard. Consequently, using a single system to track the use of RECs for compliance with another State program will maintain the integrity of clean energy programs and prevent double counting of the

renewable and environmental attributes associated with eligible renewable energy. (CPUC1_SF64-3)

Agency Response: Staff appreciates the commenters' support for the proposed clarification to indirect book-and-claim accounting for the renewable and low-CI electricity. With regard to the issuance of incremental credits based on SMUD's Greenergy program or any other green tariff program offered by utilities, that decision would be made after a thorough evaluation of the green tariff program against program requirements.

D-6.2. ***Energy Economy Ratio (EER) Updates***

D-6.2a. Multiple Comments: ***Proposed EER-Adjusted CI Tier 2 Pathway***

Comment: In summary, CleanFuture supports the addition of §95488.7(a)(3) for other transportation applications not contemplated in Table 5. (CF2_SF56-7)

Comment: The Port supports the proposal to allow for new EERs to be identified as new technologies emerge; however, the Port is concerned that the extensive work, necessary expertise, and long timeline may deter end users from acting upon this option. While additional EERs have been proposed in the second amended language, these EERs continue to overlook some pieces of port-related equipment, and many of them also seem much too low and require additional CARB Energy Efficiency Reports to confirm their accuracy. The lack of accurately derived EERs could result in fewer credits or could fail to provide enough of an economic driver for equipment conversion; thus, the Port encourages additional EERs to be formally adopted through the Energy Efficiency Report process for specific pieces of eCHE, and the Port is happy to work with CARB to provide information that may be useful in developing more accurate EERs. (POLB2_SF27-5)

Agency Response: Please refer to Response D-6.4j. in Chapter V.

In further response to POLB2_SF27-5, as part of the second 15-day changes, staff updated the definition for "Cargo Handling Equipment" to include list of equipment that would be eligible for generating credits in the program if they are powered by electricity. The proposed EER values for Electric Cargo Handling Equipment (eCHE) are based on the best data for commercially available equipment available to staff. Currently, a new EER can only be added through a rulemaking process, the proposed Tier 2 process for requesting EER-adjusted CI would enable new and innovative technologies using low-carbon fuels to participate and benefit from the program.

D-6.2b. Multiple Comments: ***Proposed EER-Adjusted CI Tier 2 Pathway***

Comment: As advanced technology eTRUs come to market, we anticipate there will be enhanced reporting capabilities to better enable the eTRU itself to serve as the FSE for LCFS purposes or to use other methods to determine electricity supplied to eTRUs. CleanFuture requests that such advanced technology eTRU technologies be evaluated

in any applications for *Tier 2 Pathways for EER-Adjusted Carbon Intensity* per §95488.7(a)(3). Any approved Tier 2 Pathways could incorporate advanced reporting capabilities as detailed by the pathway applicant. (CF2_SF56-4)

Agency Response: Please refer to Response D-6.4v in Chapter V.

D-6.2c. *Proposed EER for Electric Cargo Handling Equipment (eCHE)*

Comment: 1. *The Energy Economy Ratio (EER) should include appropriate EERs for commercialized electric Port equipment, especially yard tractors.* The Port is encouraged by a new EER catch-all category for eCHE in the proposed Rule, however, the current generic value given is 2.7 which seems much too low for many specific types of mobile freight equipment. As published in a 2017 CARB report entitled "Battery Electric Truck and Bus Energy Efficiency Compared to Conventional Diesel Vehicles," yard tractors that travel at an average of 3 mph (as they do at the port) have an EER of 7. The difference between the default EER 2.7 and the EER of 7 for one yard tractor translates into an additional $15,283 per year per yard tractor (assuming it is used 1800 hours/year and the LCFS credit price is $185). Using the default EER, the payback period from LCFS credit revenues for the premium associated with buying an electric yard tractor (which costs approximately $410,000 instead of $136,000 for a diesel version) is 46 years. The payback period for this premium using the EER of 7 is just 18 years. The cost premium for electric yard tractors is significant, and the use of the default EER may not incentivize their purchase. (POLB2_SF27-4)

Agency Response: As the analysis explicitly states, the EER value (2.7) is for "Cargo Handling Equipment (Non-Yard Trucks)" because staff recognizes that yard trucks have a greater EER value than non-yard truck cargo handling equipment. Yard trucks could share the same EER value (5.0) as on-road heavy-duty electric trucks. Please refer to Table 5 of the Final Regulation Order and Definition 153 that clarifies that yard trucks are heavy-duty trucks.

The 2017 CARB report entitled, "Battery Electric Truck and Bus Energy Efficiency Compared to Conventional Diesel Engines" was considered in the development of the EER value of 5.0 for yard trucks. Staff is committed to re-evaluate EER value for yard trucks when more relevant data become available.

D-6.3. *VIN as FSE for Incremental Credits for Residential EV Charging*

Comment: (3) The ARB should revise the regulation regarding Incremental Credits for residential electric vehicle ("EV") Charging to equalize the hierarchy of credit generation by reporting entity type and remove the requirement for Vehicle Identification Number ("VIN").

…

III. The ARB Should Amend the Incremental Credit provisions for residential EV charging related to the credit generation hierarchy and VIN reporting requirement.

…

Regarding Section 95483.2 (b)(8)(B)(4), The Smart EV Charging Group does not support reliance on Vehicle Identification Number ("VIN") as the unique identifier element for FSE registration. Residential EV charging is tied to a residence where the owner receives electricity supply, i.e., its fuel. The unique identifier which is most closely associated with fuel supply equipment providing residential EV charging is utility Service Account ID ("SAID"). An EV may legitimately charge at multiple locations, and a vehicle may change ownership and migrate to a new location. As more and more two EV households exist, the ARB will increasingly be challenged to use VIN for all fuel reporting entities when a single EV charging station may be charging and metering consumption by two vehicles, one participating in LCFS via telemetric metering and one proposing to participate via EV charging station metering, and both vehicles use the same charging station.

In addition, VIN is not easily available to all potentially claiming parties, particularly non-EDU LSEs, which are highly likely to claim Incremental Credits through the use of metering from EV supply equipment. In comparison, SAID is equally available to any non-LSE third party, either via hard copy bills or electronic data transfer.[3]

[3] Available for PG&E, SCE, SDG&E, LADWP and SMUD via utility-provided, free "Green Button" services or inexpensive third party services.

The Smart EV Charging Group notes that two EV manufacturers opposed use of VIN for LCFS reporting purposes in the manner that the ARB proposes. The ARB staff should amend Section 95483.2 (b)(8)(B)(4) to remove the explicit VIN requirement for FSE Registration, except for the case when vehicle telemetry is used as the metering source. Rather, the ARB could still use VIN for its own purposes of identifying duplicate reporting by maintaining the master list of VINs, but allow fuel reporting entities to associate with a VIN by other unique means, as noted above. (SEVCG4_SF63-4a)

Agency Response: Please see Response D-6.9 in Chapter V.

D-6.4. Multiple Comments: ***Proposed Hierarchy for Incremental Credits for Residential EV Charging***

Comment: ChargePoint recommends amending the prioritization of the incremental credits for EV charging at Single-family residences, or eliminating the hierarchy altogether. The goal of the incremental credits is to encourage more charging when there is benefit to the grid and/or when there is lower carbon intensity of the electric fuel. Smart, networked chargers enable EV drivers to easily participate in charging that meets these goals. Additionally, networked charging equipment with embedded submeters are capable of tracking and collecting data that is equal to the revenue-quality meter data of a load-serving entity meter. Currently, the hierarchy is complicated and omits opportunities for EVSEs to capture credits outside of programs with LSEs. ChargePoint recommends the following hierarchy:

1. The Load Serving Entity (LSE) supplying electricity to the EV associated with the FSE ID and metered data has first priority to claim credits;

2. The manufacturer of the EV or EVSE associated with the FSE ID has second priority; and
3. Any other entity has third priority.

By flattening the second tier, there is an opportunity for EVSE manufacturers to generate incremental credits outside of programs with LSEs. Alternatively, if ARB eliminates the hierarchy, the incremental credits could be generated by the entity that registers the residence first, which would be a more simplistic and straightforward determination of the credit generator. (CHARGEPOINT4_SF32-2)

Comment: In Section 95483(c)(1)(B)(2), when the LSE is not generating Incremental Credits, there is no basis for prioritizing one metering source over another. A major rationale for granting LSE prioritization is the direct relationship with electricity supply. All other entities would be similarly situated in this respect. The currently proposed hierarchy severely handicaps entities that are already LCFS participants, poised to deliver on the promise of credit generation and Low CI charging. (SEVCG4_SF63-4b)

Agency Response: Please see Response D-6.10 in Chapter V.

D-6.5. ***Clarification for Proposed Incremental Credits for Residential EV Charging***

D-6.5a. Comment: (2) The ARB should confirm that under the proposed amendments to 95483(c)(1)(B)(3), an Electric Distribution Utility ("EDU") cannot claim incremental credits for residential customers in a Community Choice Aggregator ("CCA") service territory because the CCA is the entity "supplying low-CI electricity", not the EDU.

…

II. <u>The ARB Should Confirm that EDUs Cannot Generate Incremental Credits for a Residential Customer That Is Supplied Electricity by a CCA.</u>

In the Final Statement of Reasons, the ARB should provide greater clarity about incremental credit generation. In the Final Statement of Reasons ("FSOR"), the ARB should clarify how it will interpret Section 95483(c)(1)(B)(3) and the term "supplying low-CI electricity." That subsection provides that:

> For non-metered residential EV charging, the EDU is eligible to generate incremental credits for supplying low-CI electricity to the EVs in its service territory.

As explained above in Section I, in the case of a CCA service territory that overlaps with an IOU's transmission and distribution service territory, the IOU will not be the entity "supplying low-CI electricity." By definition (Cal. Pub. Util. Code Sec. 331.1), the CCA is the entity that has aggregated loads within certain municipal boundaries, and therefore within these boundaries, the CCA will be the entity "supplying low-CI electricity." The ARB should clarify that in the case of CCAs, the IOU does not supply electricity to serve the aggregated load in the service territory and therefore cannot generate incremental credits for residential charging by CCA customers under Section 95843(c)(1)(B)(3).

Alternatively, consistent with the noticing requirements set forth in Cal. Govt. Code Sec. 11346.8(c), the ARB could make a non-substantial change of the term “EDU” to “LSE providing generation services” to clarify its intent in this subsection. (SEVCG4_SF63-3)

> **Agency Response:** Staff proposed that the Load Serving Entity (LSE) providing the low-CI electricity and the metered data for residential EV charging would have the first priority to claim the incremental credits. Staff would like to clarify that CCAs providing low-CI electricity to their customers would be the LSE and if they can provide the metered data for residential EV charging they would have the first priority to claim the credits over any other entity, including EDUs. Staff believes the proposed language is sufficient and therefore, did not propose the amendments suggested by the commenter.

D-6.6. Multiple Comments: ***Recommendations for Credit Generator for Multi-Family Residential EV Charging***

Comment: ChargePoint is disappointed that ARB staff reverted back to not keeping EV Charging at Multifamily Residences as a separate category from single-family charging. Multifamily residences are extremely underserved when it comes to EV charging infrastructure. In fact, ARB recently published a gap analysis and found that “A gap of between 66,000 and 79,500 charging stations are still needed to meet the demand for charging stations in multifamily housing by 2025.”[ii] If EV Charging at Multi-family Residences is its own category, credits could go directly to the multi-family residences, reducing the payback period for their investment, and creating funds to purchase more chargers and cover installation costs. Structurally, multi-family residences are very different from single-family residences. Multi-family charging can often be located in the “visitor”, “mixed-use”, or “common” areas of a multi-family residence, which are closer to “non-residential” in the usage. In most cases it is not the “consumer” or “EV driver” that is making decisions about the charging infrastructure at the property, as they would in a single-family home. It is more often the property owner, manager, and/or HOA that is making the decisions on deploying infrastructure at a level with much more complexity than a single-family home. This leads to this market segment functioning much more similarly to the non-residential/commercial market, and therefore they should be categorized accordingly in the program. Without separation, it could be an area of significant verification confusion if vehicles can register credits from chargers with multiple users, including non-residents, given the many changes proposed in the residential EV charging modifications to LCFS. ChargePoint believes that allowing multi-family residences to be able to collect credits will promote equity, breaking the cycle of predominantly lower-income Californians from being locked out of clean technology due to energy poverty.

[ii] https://arb.ca.gov/cc/greenbuildings/pdf/tcac2018.pdf

(CHARGEPOINT4_SF32-3)

Comment: (4) Multi-family housing should be treated as any other public charging installation where both LSEs and EV service providers can claim credits based on customer agreement and metered charging sessions.

…

IV. The Smart EV Charging Group Does Not Support the Reversal of the Multi-Family Charging Credit Provisions and Fears this Change May Slow Adoption of EVs within Certain Socio-economic Groups, Particularly those Relying on Low Income Housing.

The Smart EV Charging Group recommends EV Charging at Multifamily Residences should be recognized as a separate category from single-family charging. Multifamily residences are extremely underserved when it comes to EV charging infrastructure. In fact, the ARB recently published a gap analysis and found that "[a] gap of between 66,000 and 79,500 charging stations are still needed to meet the demand for charging stations in multifamily housing by 2025."[i] If EV Charging at Multi-family Residences is its own category, credits could go directly to the multi-family residences, reducing the payback period for their investment, and creating funds to purchase more chargers and cover installation costs. Structurally, multi-family residences are very different from single-family residences. Multi-family charging can often be located in the "visitor", "mixed-use", or "common" areas of a multi-family residence, which are closer to "non-residential" in the usage. In most cases, it is not the "consumer" or "EV driver" that is making decisions about the charging infrastructure at the property, as they would in a single-family home. It is more often the property owner, manager, and/or HOA that is making the decisions on deploying infrastructure at a level with much more complexity than a single-family home. This leads to this market segment functioning much more similarly to the non-residential/commercial market, and therefore they should be categorized accordingly in the program. Lastly, allowing multi-family residences to be able to collect credits will promote equity, breaking the cycle of predominantly lower-income Californians from being locked out of clean technology due to energy poverty. (SEVCG4_SF63-5)

Comment: In the presentation, slide 33 speaks to Staff's proposal to keep opt-in EDUs as the eligible credit generator for electric vehicle charging at multi-family residential properties. This proposal differs from what was presented at the June 11, 2018 workshop. In that meeting, Staff noted that the owner of FSE, or a designee, would be able to generate LCFS credits.

SRECTrade would requests that Staff consider allowing the owner of the FSE at multi-family properties to opt-in for LCFS credit ownership. EDUs would receive credits not claimed as originally suggested by Staff. We believe that the owner of the EV Charging Stations at a multi-family property would be no different than the entity owning EV Charging Stations or FSE at a non-residential property (i.e. a private workplace locations or commercial shopping centers). In many instances, the underlying owners of these properties responsible for initiating the investment in the FSE or EV Charging Stations could be the same entity. For example, many Real Estate Investment Trusts or other property owners maintain investments in both Multi-Family and Commercial or Industrial properties. It appears that allowing these property owners to be able to gain access to the same underlying incentive to make investments in EV Charging Stations and/or FSE should be available to them regardless of the type of property they own. (SREC3_SF45-1)

Comment: Envoy requests a unique provision that accommodates Envoy's unique EV fleet mobility service model and arrangement. While Envoy agrees that EDUs should be the "default" opt-in party for MUD credits, Envoy requests CARB to consider designing a provision that ensures that EV fleet mobility service providers can claim credits for the fleets that they are deploying in the MUD sector.[3]

[3] *The release of credits should be contingent on the ability of the EV fleet mobility service provider to collect all data necessary for claiming and reporting purposes.*

The Proposed Regulation Amendments have removed the MUD provision which would have allowed for Fuel Service Equipment (FSE) owners or their designees to be eligible to generate credits for the MUD sector.[4] As originally proposed, groups including EVSE providers, building owners, companies (such as Envoy), and other designees would be eligible to generate credits. Staff have communicated that "EDUs are better suited to receive these credits to help support the point of purchase rebates for EVs and infrastructure development in multi-family residences."[5]

[4] *Propose Second 15-Day Modifications; Page 50. Website Access: Website Access: https://www.arb.ca.gov/regact/2018/lcfs18/15dayatta2.pdf.*

[5] *Staff's Suggested Modifications to 2018 Amendments Proposal Low Carbon Fuel Standard Regulation; Staff Slides; Page 33; Website Access: https://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/080818handout.pdf*

Envoy recognizes the LCFS credit management core competency that EDUs possess, and agrees that EDUs are suited to support point-of-purchase rebates programs. Therefore, Envoy generally supports this modification. However, Envoy requests that CARB consider further modification to this provision to ensure that Envoy is able to receive credits, for the following and central reason:

- Envoy's core business practices align with a diverse array of statewide policy priorities focused on accelerating transportation electrification, car sharing, and equity.

Envoy is focused on EV fleet deployment and infrastructure development in MUDs, provides direct access to EVs through car sharing, and is investing in the affordable housing sector, DACs, and in low-to-moderate income communities. These practices are consistent with the 2013[6] and 2016 ZEV Action Plans[7], which prioritize car sharing, including the ZEV Action Plan goals focused on accelerating EV and EVSE deployment in MUDs, DACs, and in support of LMI households.[8] Envoy's deployment also aligns with the Safeguarding California Plan: 2018 Update, which prioritizes deployment of car sharing in affordable housing developments[9], the Clean Energy in Low-Income Multifamily Buildings Action Plan,[10]and the Low-Income Barriers Study, Part B, which recommends (in multiple use cases) the funding of programs that create mobility options, including car sharing.[11]Envoy's business model is closely aligned with Governor Brown's direction under Executive Order B-48-18 to state agencies to recommend ways to expand zero-emission vehicle infrastructure through the Low Carbon Fuel Standard Program.[12]

[6] 2013 ZEV Action Plan states the goal to: "Promote privately financed ZEV-based car sharing programs throughout the state." Website Access: http://opr.ca.gov/docs/Governors_Office_ZEV_Action_Plan_(02-13).pdf

[7] 2016 ZEV Action Plan states the goal to "Increase familiarity of ZEVs by promoting ZEV use in car sharing services, rental car opportunities, and carpool and vanpool programs." Website Access: https://www.gov.ca.gov/wp-content/uploads/2017/09/2016_ZEV_Action_Plan.pdf
[8] 2016 ZEV Action Plan seeks to: "Make home charging easy to install and use, with a special focus on Multi-Unit Dwellings (MUDs), disadvantaged and low- and moderate-income communities." Website Access: https://www.gov.ca.gov/wp-content/uploads/2017/09/2016_ZEV_Action_Plan.pdf
[9] Safeguarding California Plan: 2018 Update; Website Access: http://resources.ca.gov/docs/climate/safeguarding/update2018/safeguarding-california-plan-2018-update.pdf
[10] Clean Energy in Low-Income Multifamily Buildings Action Plan Draft (Page B-2), states the goal to "coordinate multifamily building projects with the ZEV Investment Commitment, which includes funding for projects installing zero-emission fueling infrastructure and car–sharing programs to increase access to ZEVs for low-income and DACs." And the goal to: ""coordinate EV car-sharing programs with new affordable housing developments with EV charging spaces." Website Access: https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=2ahUKEwiBhL6Gm_3cAhVIFjQIHSCMBHcQFjAAegQIAxAC&url=https%3A%2F%2Fefiling.energy.ca.gov%2Fgetdocument.aspx%3Ftn%3D223600&usg=AOvVaw2x5ZVpBYqYZk5hBNBJi4Oy
[11] CARB: Low-Income Barriers Study, Part B: Overcoming Barriers to Clean Transportation Access for Low-Income Residents, which recommends (in multiple use cases) the funding of programs that create or expand transformative clean transportation car sharing, ride sharing, bike sharing, vanpooling, micro-transit, and other mobility options; Website Access: https://www.arb.ca.gov/msprog/transoptions/sb350_final_guidance_document_022118.pdf
[12] Governor Brown's Executive Order B-48-18 requests that state agencies: "Recommend ways to expand zero-emission vehicle infrastructure through the Low Carbon Fuel Standard Program."

Based on these factors, Envoy requests this consideration. If this provision is modified to allow for our access, Envoy will be emboldened to leverage LCFS credits to expand its EV fleet and infrastructure deployment. If unaddressed, Envoy would be excluded from claiming MUD LCFS credits, despite our vehicle deployment initiatives in these crucial sectors. As such, Envoy requests CARB to further evaluate methods to provide an EV fleet mobility service provision that enables such parties to directly generate and claim credits on behalf of the EV mobility fleets that they are deploying in the MUD sector. (ENVOY2_SF55-5)

Comment: To encourage more rapid and widespread adoption of EVs by those who live in MFH, particularly in disadvantaged communities, Flux humbly recommends that the California Air Resources Board maintain the eligibility of fuel supply equipment (FSE) owners at MFH to generate low carbon fuel standard (LCFS) credits rather than assigning them to the electric distribution utility (EDU) to fund a point of purchase program as is proposed in the Second 15-Day modification document published August 13th, 2018. Flux does support a point of purchase program supported by single-family FSE.

The additional funding generated by the sale of LCFS credits from MFH FSEs will have minimal positive impact on a point of purchase rebate program that would otherwise be funded by LCFS credits sales from single-family residences with EV chargers. Conversely, the loss of MFH FSE owners' ability to claim the credits would effectively act as a regressive tax on LMI EV drivers and have a net-negative effect on EV sales to these consumers for the following reasons:

- LCFS credit revenue is critical to the business case for deploying MFH and useful in reducing total cost of ownership

- Lack of charging infrastructure at MFH is a major barrier to EV adoption
- Dealers that serve disadvantaged communities are unlikely to be effective at selling EVs, even if there is a substantial point of purchase incentive

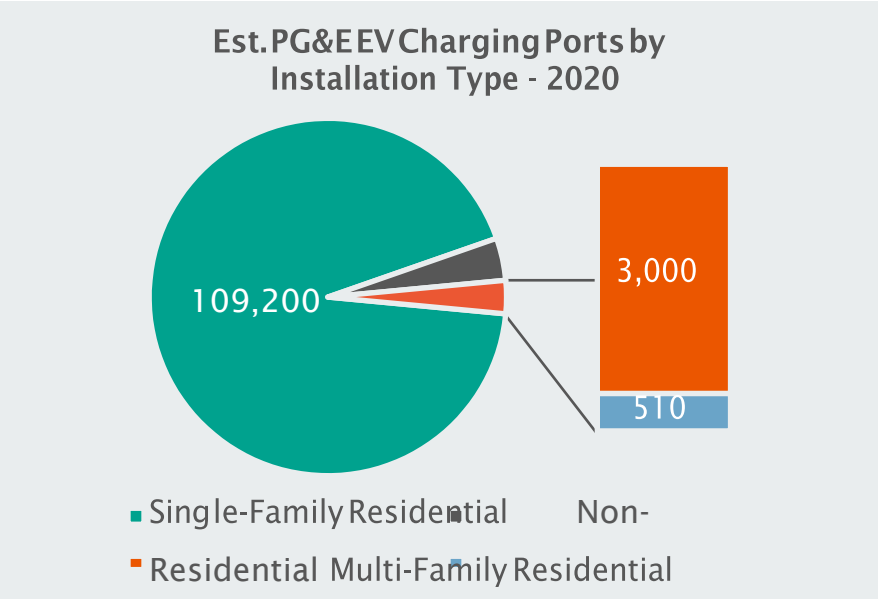
LCFS Credit Generation: Single-Family Dwarfs Multi-Family Charging

Of the 400,000 and counting EVs (both BEV and PHEV) sold in California[1], 91% of EV owners reside in single-family homes.[2] This means, at a minimum, there are 364,000 residential charging ports in the state of California. PG&E serves about one-third of all Californians, which equates to approximately 109,200 single-family charging ports. For comparison, the PG&E EV Charge Network Program seeks to deploy 7,500 non-residential and MFH Level II charging ports by 2020.[3]

[1] Alliance of Automobile Manufacturers. "Advanced Technology Vehicle Sales Dashboard" Jun. 2018. Available: https://autoalliance.org/energy-environment/advanced-technology-vehicle-sales-dashboard/

[2] Center for Sustainable Energy. "California Plug-in Electric Vehicle Owner Survey." Jul. 2012. Available: https://energycenter.org/sites/default/files/docs/nav/policy/research-and-reports/California%20Plug-in%20Electric%20Vehicle%20Owner%20Survey%20Report-July%202012.pdf

[3] Merchant, Emma Foehringer. "PG&E Launches Country's Largest Utility Sponsored EV Charging Program." Greentech Media, 17 Jan. 2018. Availabile: https://www.greentechmedia.com/articles/read/pge-launches-countrys-largest-utility-sponsored-ev-charging- program#gs.uk13mNQ



When all 7,500 chargers are installed, this will represent less than 7% of all charging points in PG&E's territory (this assumes the number of residential ports remains static, which is unlikely given projected growth in EV market penetration). Based on current program metrics, of those 7,500 charging points, fewer than half are slated for installation at MFH (40%, approx. 3,000 ports) and even fewer (17%, approx. 510 ports) are at MFH in disadvantaged communities (DACs) according to the Q4 2017 PG&E EV Charge Network Quarterly Report.[4] This means by 2020, MFH would contribute, at most, approximately 3% more LCFS credits (<0.5% from MFH in DACs) to PG&E's overall credit balance. These high-level figures conflict with the statement made by

PG&E in the company's July 5th letter: "If residential EV charging credits from multi-family residences were no longer given to the EDUs, the credit revenue available to fund this point-of-purchase incentive could be significantly lower."[5]

[4] PG&E. "EV Charge Network 2017 Q4 Report." Available: https://www.pge.com/pge_global/common/pdfs/solar-and-vehicles/your-options/clean-vehicles/charging-stations/program-participants/EV-Charge-Network_2017_Q4_Report.pdf

[5] Ali, Fariya from PG&E. "RE: Pacific Gas and Electric Comments Proposed Amendments to the Low Carbon Fuel Standard Regulation." Available: https://www.arb.ca.gov/lists/com-attach/255-lcfs18-AnJcPQRgBAgFbwBj.pdf

Loss of MFH LCFS Credit Generation Detrimental to EV Adoption in Disadvantaged Communities

Not only will the proposed changes stymie installations of FSE at MFH, they could also increase costs to EV drivers who live in MFH. Access to EV chargers at a place of residence is a critical element to accelerate EV adoption amongst all consumer groups. As EVs become cost-effective options for LMI drivers, many of whom reside in MFH in DACs, there must be some mechanism for FSE owners to recoup the high capital costs of deploying infrastructure. The simple resale of energy from the utility has little-to-no business case, unless drivers are billed at a significant markup. Flux believes this is neither an attractive nor equitable option. The ability to monetize LCFS credits encourages development of FSE at all MFH and is a way for FSE owners to generate meaningful revenue without increasing costs for LMI EV drivers just because they live in MFH.

Should MFH FSE owners retain the ability to generate LCFS credits, these credits could be sold to subsidize a driver's charging significantly. Flux calculates LCFS credit sales could lower the total cost of ownership by as much as $50 per driver per month. For reference, the median annual income for renter households in Oakland is $40,000.[6] This equates to approximately $31,800[7] after taxes, or $2,650 per month. Considering the average Oakland rent is $2,500 per month[8], $50 in additional savings could provide meaningful additional cash flow to the typical Oakland renter if they also owned an EV (which itself costs significantly less to own compared with an internal combustion engine car).

[6] Sciacca, Annie. "In costly Bay Area, even six-figure salaries are considered 'low income'." Mercury News, 22 Apr. 2017: Available: https://www.mercurynews.com/2017/04/22/in-costly-bay-area-even-six-figure-salaries-are-considered-low-income/

[7] Effective tax rate calculated using SmartAsset. Data available: https://smartasset.com/taxes/income-taxes#Yk8OXj0poE

[8] Sciacca, Annie. "In costly Bay Area, even six-figure salaries are considered 'low income'." Mercury News, 22 Apr. 2017.

If LCFS credits from MFH are assigned to the EDU for a dealer rebate program, PG&E makes the case that this will be a more equitable program in that "the point-of-purchase incentive should be available to all Californians from all residence types."[9] In reality, most of these rebates will likely be used by dealerships that are most effective at selling EVs, a majority of which are located in the highest demand markets, such as Palo Alto, Saratoga, and Los Altos.[10] This hypothesis is further supported by multiple studies that show most regular automobile dealers are ineffective at selling EVs and many actively

discourage consumers from purchasing EVs altogether.[11 12 13 14] The California Air Resources Board itself recently reported that amongst LMI consumers, "There is distrust of dealerships, and an overall feeling on the part of residents that costs are inflated especially when buying specialty vehicles, (such as zero-emission), or with incentives."[15] If LCFS credits from MFH accrue to the EDU, it is likely that LMI drivers will effectively be subsidizing EV purchases for California's wealthiest residents.

[9] Ali, Fariya from PG&E. "RE: Pacific Gas and Electric Comments Proposed Amendments to the Low Carbon Fuel Standard Regulation."

[10] The International Council on Clean Transportation. "California's continued electric vehicle market development. May 2018. Available: https://www.theicct.org/sites/default/files/publications/CA-cityEV-Briefing-20180507.pdf

[11] Cahill, Eric, Jamie Davies-Shawhyde and Thomas S. Turrentine. "New Car Dealers and Retail Innovation in California's Plug-In Electric Vehicle Market." UC Davis. October 2014. Available: https://itspubs.ucdavis.edu/wp-content/themes/ucdavis/pubs/download_pdf.php?id=2353

[12] Sierra Club. "Multi-state Survey of the Electric Vehicle Shopping Experience." Aug. 2016. Available: https://www.sierraclub.org/sites/www.sierraclub.org/files/uploads-wysiwig/1371%20Rev%20Up%20EVs%20Report_09_web%20FINAL.pdf

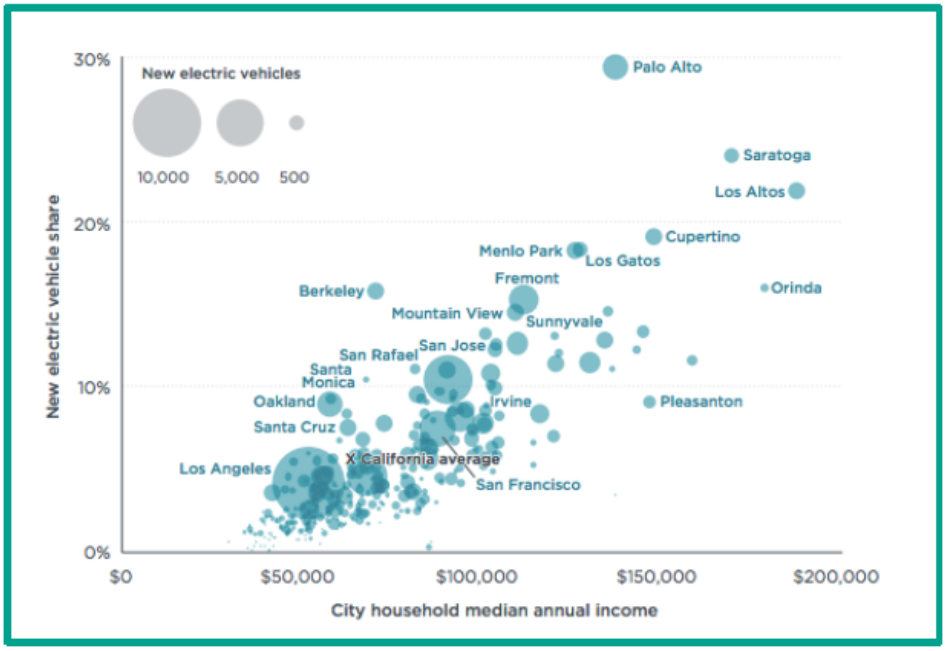
[13] Ipsos RDA. "Electric Vehicle (EV) Sales Experience and Best Practice Study." Nov. 2017. Available: https://www.ipsos.com/en- us/news-polls/rda-finds-us-dealerships-not-prepared-ev-invasion

[14] de Rubens, Gerardo Zarazua, Lance Noel & Benjamin K. Sovacool. "Dismissive and deceptive car dealerships create barriers to electric vehicle adoption at the point of sale." Nature Energy. 21 May 2018. Available: https://www.nature.com/articles/s41560-018-0152-x

[15] California Air Resources Board. "Low-Income Barriers Study, Part B: Overcoming Barriers to Clean Transportation Access for Low-Income Residents" Feb 2018. Available: https://www.arb.ca.gov/msprog/transoptions/sb350_final_guidance_document_022118.pdf

Share of California new vehicle sales that are electric by city median household income

Vehicle registrations from IHS Automotive; income data from U.S. Census - compiled by ICCT



An Alternative Proposal to Promote Innovation

In addition to point of purchase rebates, the California Air Resources Board might consider re-apportioning a small percentage of the abundant LCFS credit revenue from single-family FSE into a utility-funded program that promotes EVs in LMI communities.

This program should encourage novel approaches that solve the holistic challenges of EV ownership, which includes not only purchasing the vehicle, but also access to FSE as well as strategies for hassle-free ownership. The seminal UC Davis study New Car Dealers and Retail Innovation in California's Plug-In Electric Vehicle Market notes that innovative new products like EVs require innovative new sales models. The report contrasts very low EV buyer satisfaction at traditional auto dealerships with Tesla, which ranked much more favorably in the same study due to its the "whole product" approach. The report states: "The magnitude of these disparities is extraordinary by industry standards and indicate the problem is likely systemic."[16] These findings are echoed by the more recent studies cited in the previous paragraph.

[16] Cahill, et al. "New Car Dealers and Retail Innovation in California's Plug-In Electric Vehicle Market." Pg. 7, Lns. 46-47

Conclusion

If the California Air Resources Board is committed to providing all of its citizens the opportunity to drive an EV, it should preserve MFH FSE owners' ability to claim LCFS credits for the benefit of LMI drivers. Otherwise, these rule changes may severely hinder progress in accelerating EV adoption amongst the state's LMI consumers. (FLUX1_SF57-1)

> **Agency Response:** Staff appreciates the commenters' insights about the need for developing EV charging infrastructure for multi-family residences and agrees that it has an essential role to play for EV adoption. Staff believes several EV charging network providers are developing charging infrastructure for multi-family residences but often the conventional non-residential charging business models does not apply very well in the residential dwellings. Therefore, staff proposed utilities remain the default credit generator for EV charging at multi-family residences. This will support any point-of-purchase rebate program, and utilities are also well-positioned to promote the development of multi-family charging infrastructure while addressing equity concerns. In fact, several utilities already have programs for developing charging infrastructure in multi-family residences to promote EV adoption among low-income and disadvantaged communities. Staff believes the charging network providers would still have opportunity to work with utilities to support charging infrastructure in multi-family residences.
>
> Please also see Response D-6.15a, Proposed Credit Generator for Multi-Family Residential EV Charging, in Chapter IV.

D-6.7. *Clarification for Indirect Accounting for Renewable or Low-CI Electricity using Book-and-Claim Principle*

D-6.7a. Multiple Comments: *Green Tariff Obligations*

Comment: Publicly-owned utilities should be treated similarly to large investor-owned utilities in documenting their "green tariff" obligations.

The proposed regulation allows low-CI electricity supplied as a transportation fuel to be indirectly supplied through a green tariff program (§95488.8(i)(1)(B)). A green tariff program, includes, but is not limited to, the IOUs' Green Tariff Shared Renewables program described in California Public Utilities Code Sections 2831-2833 (§95481(68)). Section 95488.8(i)(1)(B)(3) states that "[r]etirement of renewable energy credits for the purpose of demonstrating Green Tariff Shared Renewables procurement to the California Public Utilities Commission does not constitute a double claim."

This language should be expanded to recognize that green tariff programs may also be provided by POUs, and allow equitable treatment of REC retirement under these programs.

POUs are authorized under Public Utilities Code 399.30(c)(4), to offer "voluntary green pricing or shared renewable generation" programs and exclude from its total retail sales the kilowatthours generated by an eligible renewable energy resource that is credited to a participating customer pursuant to these programs. Similar to the need for large IOUs to document their green tariff programs to the California Public Utilities Commission, POUs likely will need to document participation in their own green tariff programs to the California Energy Commission (CEC), in order for the CEC to determine their RPS compliance obligations. Accordingly, San Francisco proposes changes to section 95488.8(i)(1)(B)(3) as shown in the attachment. (CCSF4_SF13-2)

Comment: (6) All LSEs should be allowed to fairly compete with California's large investor owned utilities ("IOUs") in claiming incremental credits and offering a Zero-CI Green tariff to their customers.

…

VI. <u>All LSEs Should Be Allowed to Fairly Compete with California's Large IOUs in Offering a Zero-CI Green Tariff to Their Customers.</u>

Under state law, California's largest IOUs and all of California's publicly owned utilities ("POUs") are allowed to exclude their green tariff sales from their otherwise applicable RPS compliance obligations.[4] This option is not available to all other LSEs, including community choice aggregators ("CCAs"), energy service providers ("ESPs") and California's smaller IOUs. The creation of a green tariff program by a CCA or small IOU does not absolve the seller from still meeting the applicable RPS standards, which apply to all of its retail sales. Thus, a CCA or small-IOU offering a 100% renewable energy zero-CI green tariff to its LCFS customers must still retire sufficient Renewable Energy Credits ("RECs") to meet its RPS obligation. Assuming for example, a 30% RPS standard, a LSE that sells 100 MWh of green tariff energy must still retire 30 MWh of RECs to meet the RPS standard. What distinguishes a green tariff is the additional sales (70% in this case) that are voluntarily being greened up by the LSE and purchased by the LCFS customer.

[4] Public Utilities Code Sections 2831-2833 and 390.30(c)(4).

Such an approach does not result in any double-counting of RECs. The current default (California grid) emissions value for electricity, for example, already reflects that the

California electric system is becoming increasingly GHG-free by meeting the required RPS-standards. Essentially, the current CI- intensity for the California electric system already reflects load-serving entities achieving the applicable RPS standards (30% assumed in this case). The difference in CI intensity between the default California grid emission value and the green tariff value of zero, represents the difference between meeting versus exceeding the applicable RPS standard (i.e. the additional 70% of renewable energy) and providing 100% RPS-eligible zero-CI power.

Accordingly, the proposed regulations should be clarified to allow a LSE to claim for purposes of RPS compliance, if needed, the proportion of the LSE's green tariff portfolio that corresponds to the green tariff's applicable RPS obligation, without affecting the LSE's eligibility to receive full credit under the LCFS program for providing a zero or low-CI product.

This approach is necessary to allow smaller IOUs to receive full credit for offering a green tariff based EV charging option. This approach would also allow CCAs and ESPs to fairly compete with the larger IOUs in offering zero-CI green tariff options (as allowed for incremental crediting), as well as for all non-EV uses of electric energy for transportation. (SEVCG4_SF63-7)

> **Agency Response:** Staff would like to clarify that the proposed definition of "green tariff" would allow the green tariff offered by Public-owned Utilities (POU) or Community Choice Aggregators (CCAs) to be eligible for indirect book-and-claim accounting of low-CI or renewable electricity as long as all the requirements as set forth in section 95488.8(i)(B) are met.

D-6.7b. Comment: BART is concerned, however that a change made in the second 15-day modifications to the section of the LCFS Regulation that would provide for book-and-claim accounting may be in conflict with CARB's intent to recognize Low-CI Electricity from sources other than "eligible renewable energy resources" ("ERRs") under the state's Renewables Portfolio Standard ("RPS"). Specifically, Section 95488.8(i)(1)(A) of the proposed Regulation was modified in the recent 15-day changes to require the following in order for electricity imports from out of state to be eligible for book-and-claim accounting:

> The low-CI electricity must be supplied to the grid within a California Balancing Authority (or local balancing authority for hydrogen produced outside of California) or alternatively, meet the requirements of California Public Utilities Code section 399.16, subdivision (b)(1).

The statutory reference to Public Utilities Code Section 399.16(b)(1) refers to the delivery requirements for "Bucket 1" product under the RPS. However, Section 399.16(b)(1) expressly requires that a generation source must be an ERR in order to qualify.[1] This is in direct conflict with the definition of "Low-CI Electricity" in the proposed LCFS Regulation, which extends to low-carbon sources of electricity other than ERRs. Additionally, the delivery requirements of Section 399.16(b)(1)(A) would create other administrative issues if applied to imports from non-ERRs, such as

deliveries of ACS electricity. For example, deliveries of ACS electricity are not accompanied by the type of highly granular generation or metering data that is typically required to demonstrate compliance with 399.16(b)(1)(A).

[1] Pub. Util. Code § 399.16(b)(1).

In order to clarify that out-of-state sources of Low-CI Electricity that do not qualify as ERRs may be eligible for book-and-claim accounting under the LCFS, CARB should modify Section 95488.8(i)(1)(A) of the proposed Regulation to refer to the definition of "direct delivery of electricity" under Section 95102(a) of CARB's Mandatory Reporting Regulation (17 Cal. Code Regs. §§ 95100-95163, hereinafter "MRR"). As defined in the MRR, "direct delivery of electricity" requires the following:

> "Direct delivery of electricity" or "directly delivered" means electricity that meets any of the following criteria:
>
> > The facility has a first point of interconnection with a California balancing authority;
> >
> > The facility has a first point of interconnection with distribution facilities used to serve end users within California balancing authority area;
> >
> > The electricity is scheduled for delivery from the specified source into California balancing authority via a continuous physical transmission path from the interconnection of the facility in the balancing authority in which the facility is located to a sink located in the State of California; or
> >
> > There is an agreement to dynamically transfer electricity from the facility to a California balancing authority.[2]
> >
> > [2] 17 C.C.R. § 95102(a).

This definition was developed by CARB for use in reporting electricity deliveries from "specified sources" under the MRR, and is a better fit for the reporting of non-ERR imports of Low-CI Electricity under the LCFS Regulation.

BART recommends that Section 95488.8(i)(1)(A) of the proposed Regulation be modified as follows (proposed additions shown in underline):

> Reporting entities may report low-CI electricity used as a transportation fuel or as an input to hydrogen production delivered through the grid without regard to physical traceability if it meets all requirements of this subarticle. The low-CI electricity must be supplied to the grid within a California Balancing Authority (or local balancing authority for hydrogen produced outside of California) or alternatively, meet the <u>delivery</u> requirements of California Public Utilities Code section 399.16, subdivision (b)(1)<u>, or the definition of "direct delivery of electricity" provided in Title 17, Division 3, Chapter 1, Subchapter 10, Article 2 (Mandatory Greenhouse Gas Emission Reporting), section 95102(a) of the California Code of Regulations</u>.

If CARB chooses not to modify the proposed LCFS regulation in another round of 15-day modifications, BART respectfully requests that CARB clarify in the Final Statement of Reasons ("FSOR") the following two issues: (1) the reference to Public Utilities Code Section 399.16(b)(1) in Section 95488.8(i)(1)(A) of the LCFS Regulation is intended to incorporate only the delivery requirements of 399.16(b)(1), and not the requirement that an electric generation source be an Eligible Renewable Energy Resource under the RPS, and (2) imports from Low-CI Electricity sources that do not provide the necessary generation or meter data for reporting compliance with the requirements of Public Utilities Code Section 399.16(b)(1) may nevertheless be eligible for book-and-claim accounting under Section 95488.8(i)(1)(A) of the LCFS Regulation if the reporting entity provides other information (such as eTags) demonstrating that the imported electricity satisfies the "direct delivery of electricity" requirements under the MRR. (BART3_SF35-3)

Agency Response: Low-CI electricity has been clarified in the definitions as:

> any electricity that is determined to have a carbon intensity that is less than the average grid electricity for the region, including but not limited to an "eligible renewable energy resource" as defined in Public Utilities Code sections 399.11-399.36 under the California Renewables Portfolio Standard Program.

Under the proposed book-and-claim accounting mechanisms described in section 95488.8(i)(1), the "low-CI electricity must be supplied to the grid within a California Balancing Authority (or local balancing authority for hydrogen produced outside of California) or alternatively, meet the requirements of California Public Utilities Code section 399.16, subdivision (b)(1)." Staff's intention for this requirement is to specify the <u>delivery</u> requirements for the "low-CI electricity." Although section 399.16, subdivision (b)(1) refers to "eligible renewable energy resources", it was not staff's intention to limit the book-and-claim accounting to only these resources.

D-6.8. Multiple Comments: *Smart Electrolysis and Indirect Book-and-Claim Accounting for Low-CI or Renewable Electricity for Hydrogen Production*

Comment: Further, the *Time-of-Use* pathway definition (rather than *Smart Electrolysis* definition) should be restored to include electrical power used in all hydrogen production pathways.

…

Section 954861(f)(2): <u>*Time-of-Use Pathways*</u> for Hydrogen Production. An entity can generate credits, in addition to credits generated pursuant to subsection (1), above, for improvements in the CI of electricity used for electrolysis<u>***, or for hydrogen compression, liquefaction, distribution or dispensing,***</u> to produce hydrogen due to time of use <u>***time of use***</u> pursuant to section 95488.5 and the credit calculation in section 95486.1(c)(2)(B). (AL2_SF1-4)

Comment: Lastly, we need to insure that Book-and-Claim Accounting can be used for all aspects of hydrogen production.

…

Section 95488.8(i)(1): *Book-and-Claim Accounting for Renewable or Low-CI Electricity Supplied as a Transportation Fuel or Used to Produce Hydrogen*. Reporting entities may use indirect accounting mechanisms for renewable electricity to reduce the CI of low-CI electricity supplied as a transportation fuel or for hydrogen production through electrolysis***, and for hydrogen compression, liquefaction, distribution or dispensing,*** for transportation purposes (including hydrogen that is used in the production of a transportation fuel), provided the conditions set forth below are met: (AL2_SF1-5)

Comment: Similar changes would follow in Section 95488.1, Section 95488.5, Section 95488.10(a)(4) and Section 95491. Without these changes, a hydrogen producer has very limited incentive to improve renewable content within a given pathway and the targeted CI reductions will likely become irrelevant. (AL2_SF1-6)

Comment: Further, the Time-of-Use pathway definition (rather than Smart Electrolysis definition) should be restored to include electrical power used in all hydrogen production pathways.[2]

[2] Section 95486.1(f)(2): *Time-of-Use Pathways* for Hydrogen Production. An entity can generate credits, in addition to credits generated pursuant to subsection (1), above, for improvements in the CI of electricity used for electrolysis*, or for hydrogen, compression, liquefaction, distribution or dispensing,* to produce hydrogen due to time of use smart electrolysis pursuant to section 95488.5 and the credit calculation in section 95486.1(c)(2)(B), where: Electricity is the total quantity of low-CI electricity supplied to the electrolyzer for hydrogen production*, or used for hydrogen compression liquefaction, distribution or dispensing*.

(H2IND3_SF6-4b, H2IND4_SF7-4b)

Comment: Lastly, the Book-and-Claim Accounting should be allowed for use for all aspects of hydrogen production.[3]

[3] **Section 95488.8(i)(1):** *Book-and-Claim Accounting for Renewable or Low-CI Electricity Supplied as a Transportation Fuel or Used to Produce Hydrogen.* Reporting entities may use indirect accounting mechanisms for renewable electricity to reduce the CI of electricity supplied as a transportation fuel or for hydrogen production through electrolysis, and for hydrogen compression, liquefaction, distribution or dispensing, provided the conditions set forth below are met:

Similar changes would follow in Section 95488.1, Section 95488.5, Section 95488.10(a)(4) and Section 95491. Without these changes, a hydrogen producer has very limited incentive to improve renewable content within a given pathway. (H2IND3_SF6-4c, H2IND4_SF7-4c)

Agency response: Staff did not propose any changes based on the commenters' recommendation. The intent of the book-and-claim accounting and smart electrolysis pathway (referred to as time-of-use pathway in the comment letter) is to offer greater flexibility to promote the use of low-CI electricity used for the production of hydrogen through electrolysis. Indirectly supplied low-CI

electricity used for compression, liquefaction, distribution, or other ancillary services at hydrogen production or station facility is not eligible to be claimed under the book-and-claim accounting or smart electrolysis pathway.

Please see also Response J-13 in Chapter IV.

D-6.9. *Proposed Changes to Electric Forklifts Provisions*

Comment: 2. *Allow FSE owners to use the same simplified calculation that electrical distribution utilities (EDUs) use to calculate credits*. EDUs are able to simply multiply the number of pieces of electric equipment in the utility's service territory by the daily average electricity use per vehicle by the work days of the year to calculate the credits they can claim from forklifts. FSE owners must either have dedicated meters that serve the forklifts or use a calculation that requires FSE owners to keep track of the depth of discharge, battery capacity rating, charger efficiency rating and charge return factor. Now that electric mobile equipment qualifies for LCFS credits, installing many meters and/or keeping track of all of these factors for each piece of equipment will become cumbersome and cost prohibitive for FSE owners. (POLB2_SF27-6)

Agency Response: Please see Response D-6.15a in Chapter V.

D-6.10. *Proposed Charging and Smart Electrolysis*

D-6.10a. Comment: ARB proposed a carbon intensity for electric vehicle charging depended on the time of day. it was unclear from AARP presentation weather these carving intensity value is for based on the California great model or what the mix of resources was. please provide a table of the electricity resource mix and California great calculation for each time of day. This can be accomplished with a simple external calculator. absent such an effort the carbon intensity values may exclude the upstream life cycle emissions (LCA7_SF5-1)

Agency Response: Smart charging CI values are based on the marginal emission rates for California grid electricity as calculated in Avoided Cost Calculator (ACC) and the California grid average electricity CI. Please see Response D-6.1i in Chapter IV.

Staff would also encourage the commenter to review the methodology for calculating CI values for smart charging pathways provided in Attachment C: Proposed Second 15-day Modifications to the CA-GREET3.0 Technical Support Document, posted on August 13, 2018.

D-6.10b. Comment: 3. *Smart charging provisions should apply to electricity supplied to equipment at the Port.* The book-and-claim and green tariff provisions qualify for electricity supplied to mobile equipment, and the smart charging provisions should also. The Port does not believe that CARB intended for smart charging provisions that are available for electric equipment not be applicable to electric equipment at the port. Smart charging would allow for strategic charging when the grid emission factors are

lower than average, which results in less emissions per charge and more credits. (POLB2_SF27-7)

> **Agency Response:** Staff appreciates the commenter's suggestion and believes smart charging across variety of electric transportation applications could be helpful in promoting electricity as a low carbon transportation fuel. However, to avoid reporting and auditing complexities with smart charging pathway, staff proposed to limit its availability only for EV charging. Staff would assess the impact of smart charging pathway for EV charging and may consider allowing other electric transportation applications to use it for reporting electricity in the LRT-CBTS.

D-6.10c. Comment: In § 95488.5(f), Table 7-2 does not differentiate between weekdays and weekends/holidays. As electricity demand varies between weekdays and weekends, CARB may consider incorporating two smart charging CI tables: one with CI values for weekdays and one for CI values for weekends and holidays. (WSPA7_SF29-9)

> **Agency Response:** Staff appreciates the commenter's thoughts and would like to note that the CI values for smart charging pathway are averages for each hourly window in each calendar quarter. There are a variety of factors that affect electricity demand and no two days have exactly the same demand profile. In an ideal scenario, the smart charging pathway would rely on real-time data to assess most accurate CI values. However, currently requiring real-time reporting or breakout by weekday and weekend would create complexity in the reporting system with a small incremental benefit to the data quality. Therefore, staff proposed using average CI values for smart charging pathway reporting until CARB could work with stakeholders to create advanced reporting tools that could allow more granular reporting in future.

D-6.10d. Comment: PG&E supports the new methodology for determining the hourly electricity carbon intensities by using the marginal emission signal from the California Public Utilities Commission (CPUC)'s Avoided Cost Calculator (ACC). The ACC model has been used in many cost-effectiveness proceedings, and calculates the marginal greenhouse gas emissions from actual day-ahead prices in the California Independent System Operator (CAISO) energy market, adjusted for increased penetration of renewables going forward. The revised carbon intensities using this methodology will more accurately reflect actual curtailment and marginal heat rates. Further, the ACC methodology will ensure that carbon intensity values are more aligned with the proposed IOU time-of-use rate periods.

PG&E notes that the ACC outputs are designated in Pacific Standard Time (PST), and therefore suggests that ARB clarify that the "Hourly Windows" in the footnote to Table 7.2 refer to PST. ARB should also consider re-calculating Table 7.2 based on Pacific Prevailing Time (PPT) in future updates to the regulation. PG&E appreciates ARB staff's attention to the Smart Charging Lookup Table issue and the revisions made to the methodology for greater accuracy. (PGE3_SF49-5)

Agency Response: Staff appreciates the commenter's support for the proposed methodology for calculating CI values for smart charging pathway. The smart charging CIs are based on the marginal emissions rates provided in the Avoided Cost Calculator for hourly windows in the Pacific Standard Time (PST). In order to avoid complexity of updating the smart charging CI table to adjust for the daylight saving time and misalignment of such updates with the quarterly reporting scheme, staff would like to clarify that the hourly breakdown of electricity reported for smart charging pathway must be in Pacific Prevailing Time (PPT). Staff would consider updating the smart charging provisions in future to better align with real-time marginal emissions rate for grid electricity.

D-6.10e. Comment: 1. Smart Charging – We request clarification that by requiring that residences enroll in a Time-of-Use (TOU) rate plan to create incremental LCFS credits for Smart Charging, that the customer must be enrolled in an electric vehicle specific TOU rate if offered by the load serving entity serving the residence, or another TOU rate if not offered.

…

The modified LCFS regulation, in §95483(c)(B)(l), specifically requires that to receive incremental LCFS credits for smart charging, the residence must be enrolled in a TOU rate plan, if offered by the load serving entity serving the residence. We support this provision because it aligns state incentives for electric vehicle charging. The CPUC has approved a number of TOU rates for the IOUs specific to electric vehicle (EV) drivers, with price signals that provide EV drivers with the incentive to charge at times of the day that are most beneficial to the grid and that lead to reduced greenhouse gas emissions.

Because the LCFS Smart Charging provision is for utility customers who will be charging an EV, we ask CARB to clarify that this provision means that the customer must be enrolled in an EV-specific TOU rate if offered by the load serving entity serving the residence, or another TOU rate if not offered. (CPUC1_SF64-5)

Agency Response: Staff would like to clarify that to be eligible for smart charging pathway a residence must be enrolled in an EV-specific time-variant rate plan, if offered by the Load Serving Entity (LSE). The entity using smart charging pathway for reporting electricity must be able to provide records for the enrollment in the EV specific time-variant rate, upon request by the Executive Officer. If the LSE does not offer an EV specific time-variant rate plan then the reporting entity must provide documentation demonstrating that. Staff believes this change would ensure the smart charging pathway aligns with utility offered time-variant rates to provide a consistent signal about when EV charging should be occurring to deliver maximum grid benefits.

D-6.11. Requirements for Entities Generating Credits for Supplying Electricity as a Transportation Fuel

Comment: Although CARB requests in § 95491 (d)(3)(A) that the EV credit generators educate the public and consumers on the benefits of EV transportation, all social and environment issues associated with battery manufacturing, including mining for lithium and cobalt, and disposal of used batteries should be disclosed to the public as well. (WSPA7_SF29-15)

> **Agency Response:** Staff would like to note that requirements in section 95491(d)(3)(A) are unique in the sense that they only apply to entities generating credits for EV charging. Credit generators for other fuels are not subject to similar requirements. The life cycle analysis of all fuels in the LCFS does not include emissions associated with manufacturing of process equipment/vehicle parts, sourcing of building materials, decommissioning/end-of-life for equipment and vehicles, and other emissions related to equipment that are considered to be outside of the scope of a fuels regulation.

D-6.12. *New Electric Transportation Applications*

D-6.12a. Multiple Comments: *Fuel Reporting Entity and Credit Generator for Proposed New Electric Transportation Applications*

Comment: However additional changes introduced in the Second Notice of Public on August 13, 2018 in certain sections are problematic as these second changes inadequately convey the incentive to the fleet owner; the entity that makes the investment, deployment, and use decisions. (CF2_SF56-2b)

Comment: The fleet owner for forklifts, eTRU, eCHE, or eOGV to be the first priority credit generator.

…

§ 95483. Fuel Reporting Entities.

95483 (c) (6)

(…)

(6)~~(5)~~ Electric Transport Refrigeration Units (eTRU), Electric Cargo Handling Equipment (eCHE), Electric ~~**Auxiliary Engines**~~ **Power** for Ocean-going Vessel (eOGV).

> (A) For electricity supplied to eTRU, eCHE, or eOGV, the ~~operator~~ owner of the eTRU, eCHE, or eOGV ~~FSE~~ is the fuel reporting entity and the credit generator ~~**for electricity supplied to a** specified **each respective unit.**~~
>
> (B) Subsection (A) above notwithstanding, the **eTRU, eCHE, or eOGV** ~~operator~~ owner ~~**of the FSE**~~ may elect not to be the credit generator and instead designate

another entity to be the credit generator if the two entities agree by written contract that:

1. The **eTRU, eCHE, or eOGV** ~~operator~~ owner ~~**of the FSE**~~ will not generate credits and will instead provide the electricity data to the designated entity for LCFS reporting pursuant to sections ~~**95483.1**~~ **95483.2(b)(8)**, 95491 and 95491.1.

2. The designated entity accepts all LCFS responsibilities as the fuel reporting entity and credit generator. (CF2_SF56-5)

Agency Response: As part of the second 15-day changes, staff proposed to designate the owner of the Fueling Supply Equipment (FSE) to be the eligible entity for generating credits for supplying electricity to electric transport refrigeration units (eTRU), electric power to ocean-going vessels (eOGV), and Electric Cargo Handling Equipment (eCHE). This is consistent with other electricity categories where the first fuel reporting entity and credit generator is the FSE owner. The FSE owner would still have an option to designate any other entity to be a credit generator on its behalf.

D-6.12b. Multiple Comments: ***FSE Registration for Electric Transportation Refrigeration Unit***

Comment: Furthermore, certain changes made in the Second Modified Text in respect to the First Modified Text are incompatible with the manner that industry uses certain equipment and/or equipment reporting capabilities (i.e., few eTRUs have data acquisition reporting capabilities to serve as FSEs) and could impede instead of incentivize adoption. (CF2_SF56-2c)

Comment: At this stage of TRU electrification market development for trucks, trailers, and rail cars, the terms “Fueling Supply Equipment” and “FSE” should refer to the equipment that supplies electricity to the eTRU instead of the eTRU itself. The capability of data capture from the legacy eTRUs in use today is limited in some eTRU models and non-existent in other eTRU models. Currently, the equipment that can best capture eTRU usage data is the sub meter. The sub meter also serves as an aggregating point for all TRU electric outlets and is the most efficient way to track electricity usage in eTRU units. (CF2_SF56-3)

Comment: For eTRU the FSE should refer to the facility or location where electricity is dispensed for fueling unless otherwise approved per §95488.7(a)(3).

…

§95483.2. LCFS Data Management System.

Registration of Fueling Supply Equipment

95483.2 (8) (B) (6)

(…)

6. For electric forklifts, eTRU, eCHE, or eOGV, FSE refers to the facility or location where electricity is dispensed for fueling. ~~**Fuel reporting entities for electric forklift, eCHE, or eOGV must provide name of the facility at which FSE is situated, street address, latitude, and longitude of the FSE location**~~**. If there are multiple FSEs capable of measuring the electricity dispensed at the facility or location, then it is optional to provide serial number assigned to each equipment by the OEM and the name of OEM.**

~~(H) 7. For eTRU, FSE refers to each eTRU. Fuel reporting entities for eTRU fueling must provide the serial number assigned to the unit by the OEM and the name of the OEM.~~ (CF2_SF56-6)

Agency Response: Please see Response D-6.15d in Chapter V.

D-6.13. ***Point-Of-Purchase Rebate***

D-6.13a. Multiple Comments: ***Recommending that the LSE be the Base Credit Generator for Residential EV Charging instead of the EDU***

Comment: (1) Allow all Load Serving Entities ("LSEs") to claim base credits under Section 95483(c).

…

I. Remove the Arbitrary Distinction Between EDUs and Other LSEs.

Under the proposed amendments to the LCFS, only EDUs can generate "base credits" for residential EV charging sessions. In the "pre-rulemaking" public stakeholder process and at the April 2018 Board Hearing to consider "45 Day" amendments, stakeholders raised concerns about the use of the term "Electricity Distribution Utility" ("EDU"). The "base credits" will likely represent the majority of credit value for residential EV charging sessions. Consequently, EDUs (in particular, IOUs) will have a considerable amount of credit value as compared to CCAs.

A growing number of California residents receive their electricity generation services from a CCA and the transmission and distribution services from IOUs (i.e., a residential customer is both a CCA and IOU customer). CCAs and IOUs compete with one another both for retail customers and in the wholesale electricity markets. We acknowledge the ARB's efforts to rectify the situation by allowing "Incremental Credits" to be generated by CCAs, service providers and EDUs when the carbon intensity of the supplied electricity is less than the "state-wide grid average." However, the possible grant of incremental credits does not change that the delineation favoring IOUs in the base credit structure is arbitrary and capricious.

There is no rational basis for distinguishing between CCAs and EDUs, nor does the record support this delineation between generation providers. The only rationale

provided was that the EDU distinction was that to avoid "substantially restructuring the program, eligibility for base credits remains with the electricity distribution utilities (EDU)."[1] However, in the August 13 and 15, 2018 Amendments to the LCFS, the ARB did just that - it "substantially restructur[ed] the program", in particular, the IOU's LCFS revenue usage. The August 13 and 15, 2018 Amendments substantially restructured the program by directing EDUs to revise their rebate programs and contribute specified percentages of credit value to a state-wide rebate fund. This change is substantial in that it materially changes existing programs and will require follow-on rulemaking activities at the CPUC.

[1] See March 6, 2018 ISOR at p. III-38.

There is evidence in the record that confirms that base credits should be awarded to the CCAs.[2] As detailed in prior written and oral comments at the April 2018 Board Hearing, CCAs provide generation services to their customers. IOUs transmit the electricity the CCAs have either purchased or generated to the end use customer over IOU-owned transmission and distribution facilities. As the supplier of electricity and the entity responsible for choosing which power plants to source from, the CCA controls the carbon content of the electricity provided to the customer. In other words, CCAs control the carbon content of the charging sessions supporting the base credit awards. CCAs are the local power suppliers that more closely engage with customers and are therefore in the best position to further the fundamental policy objectives of the LCFS, which include reducing carbon emissions in the transportation sector.

[2] See for example, Smart EV Charging Group Comments on 45 Day LCFS language (April 23, 2018).

Section 95483(c) of the Regulation should be revised to make CCAs eligible to generate base credits. The ARB should replace the term Electric Distribution Utility with "Load Serving Entity." Under this proposal, the CCAs would contribute allowances to the statewide rebate program or use their allowance value as publicly owned utilities would be allowed to under the August 13 and 15, 2018 Amendments (i.e., as set forth in the proposed amendments to the table in Section 95483(c)). (SEVCG4_SF63-2)

Agency Response: Please see Response D-6.23 in Chapter IV.

D-6.13b. Multiple Comments: ***General Support for a Statewide Point-of-Purchase Rebate Program***

Comment: The Southern California Public Power Authority (SCPPA) supports proposed LCFS programmatic changes for this issue and appreciates CARB's dedication to work with stakeholders to advance implementation of a POP Rebate Program in a mutually agreeable manner.

…

Seven SCPPA Members have currently opted-in to the Low Carbon Fuel Standard Program and value being able to participate in this Program. The opted-in members offer a variety of programs that enable ratepayers to understand and enjoy the benefits of operating vehicles that run on low carbon fuels; examples include free charging,

education and outreach, access to charging infrastructure, new electric vehicle rebates, and used electric vehicle rebates for low-income customers.

SCPPA Members remain confident in their ability to participate in the LCFS Program through collective conversations with CARB staff, CalETC, and the Auto Alliance that have enabled clearer direction in the most recent 15-day changes. Specifically, SCPPA appreciates and supports collaborative efforts with CARB and CalETC that have:

- Set four rebate tiers to determine rebate amounts based upon battery capacity;
- Defined publicly-owned utilities (POUs) based upon 2017 load (large, medium, small);
- Set different percentages of credit amounts for Electrical Distribution Utilities to contribute to the statewide POP for Large POUs, Medium POUs, and Small POUs – potentially subject to adjustments in 2025; and
- Set lower POP contribution percentages in years 2019 through 2022, which minimizes interruption to popular local programs. (SCPPA1_SF4-1)

Comment: While the updated zero emission transportation provisions support broader electrification, the current program does not fully utilize the LCFS' potential to create incentives for the purchase of ZEVs. We support the creation a statewide "on the hood" clean fuel reward for new EV buyers, which would be administered by a statewide third-party administrator, subject to approval by CARB, based on residential charging data recorded by the vehicles. Point-of-sale incentives are the most effective way to drive consumer ZEV adoption, especially for non-affluent buyers.

This approach provides significant consumer benefits and improves upon the existing program design. We support the staff proposal to require, in the regulation, a minimum utility percentage contribution to the statewide rebate program. This threshold will assure that incentives reach meaningful amounts.

We support the staff proposal to add four tiers to determine the rebate amount based on battery capacity of the EV, similar to federal tax credit tiers. This would ensure EVs with higher battery capacity get higher rebates as compared to EVs with lower battery capacity, and will help to accelerate deployment of stronger battery plug-in hybrids that meet most of the usual driving needs of consumers.

Similar to other existing state ZEV programs, we also recommend that the Point-of-Purchase program incorporate a means test, to maximize the effectiveness of incentives by reserving them for non-affluent Californians purchasing non-luxury vehicles. (CCAALACVAQ1_SF16-7)

Comment: The LCFS is an important, complementary policy in the state of California for supporting the transition to lower carbon transportation, and we support creation of the Point-of-Purchase (POP) Clean Fuel Reward, also known as "POP into Electric".

…

However, the PEV and FCEV market faces headwinds in the coming years. First, several manufacturers will reach their limit for federal tax credits (up to $7,500 per PEV, FCEVs do not receive this credit) over the next year. Second, all customers, and especially mainstream customers, must want to adopt PEVs and FCEVs to push this market beyond six or seven percent. These customers demand the vehicle attributes – range, refueling time, cost, convenience, capability, etc. – that match or exceed their current vehicle. These facts underscore that now more than ever we need ongoing purchase rebates and development of both electric charging and hydrogen refueling infrastructure as we work to maintain this achievement and strive to continue growth of the electric vehicle market.

As directed by the Board at its April 2018 meeting, the Executive Office was asked to explore options to increase on-the-hood Clean Fuel Rewards for electric vehicles, funded by LCFS residential charging revenue as follows:

> Explore with stakeholders the opportunities to increase the magnitude of ZEV vehicle rebates funded by sale of LCFS credits. Focus these discussions on the possibility to offer the rebate at the point of sale of the vehicle. Evaluate the opportunities to harmonize rebate designs statewide and explore synergies with other rebate programs, including the Clean Vehicle Rebate Project.[3]
>
> [3] Board Resolution 18-17.

As a result, we have been working diligently with the utilities to scope such a program, following the guidelines to implement a statewide, transparent, and larger Clean Fuel Reward applied at the point of purchase to help further assist in advancing electric vehicle sales in the state. As explained further below, our two associations support the proposed 2nd 15-Day Changes to create a Point-of-Purchase (POP) Clean Fuel Reward, also known as "POP into Electric." …

We would like to recognize staff's efforts and diligence in working with industry to understand, develop and propose this language through the public regulatory process, including hosting a workshop in August to present the regulatory text and plans associated with the "POP into Electric" program. It is also important that we recognize the assistance of Vice Chair Sandy Berg, who has been integral in bringing the utility and automotive industry to consensus on many critical aspects of the "POP into Electric" program. (AAMGA2_SF18-1)

Comment: Support for Clean Fuel Rewards and the "POP into Electric" Program

One of many challenges that PEVs and FCEVs continue to face is that the cost of the technology is still more expensive than gasoline engines. Thus, the need for incentives is as important as ever, particularly as many companies face the end of the Federal Tax Credit, which currently provides up to $7,500 for PEVs. **That is why we have been coordinating with the utilities to develop and scope out a statewide "POP into Electric" program, to provide additional on-the-hood vehicle incentives in a simple and fast manner, providing value to every customer that decides to buy or lease a PEV.** This program will likely be an important backstop to the Federal Tax

Credit as it phases out, and therefore, it is important that we work to maximize the Clean Fuel Reward.

California has stepped up to the plate, providing over $500 million in vehicle incentives, including the Clean Vehicle Rebate Program, numerous equity benefits, like the Charge Ahead and Enhanced Fleet Modernization programs, and additional incentives for HOV lanes, chargers, hydrogen infrastructure and more. These programs in combination have been integral to the success of electric vehicles in the state, and we appreciate ARB's ongoing commitment to working to fund these incentives programs and look for innovative ways to make sure the EV market is growing across all communities in the state. These programs should continue and are all needed, continuing to help offset costs while also addressing the state's ongoing concerns related to equity. They should also be viewed as necessary and important complements to the creation of the "POP into Electric" program, which will work to encourage residential electric charging as a key aspect of PEV use and provide additional value to customers through application at point of purchase.

Every electric vehicle that is purchased or leased in the state and charged at home contributes to this program, by generating credits that can earned by the utility companies and contributing to a real and increasing reduction in petroleum use. Based on LCFS credit prices of around $150 per credit, every single PEV that is sold will generate $4,000 in LCFS residential charging revenue.

As a result, every PEV sold or leased in the state should be eligible to receive a Clean Fuel Reward, because those consumers are contributing to the state's goals by choosing to go to electric. Any separate approach that would limit availability would be inequitable to those customers that have gone electric, regardless of location, income, or vehicle preference.[4] Furthermore, all manufacturers that are selling PEVs now, or in the near future, have invested heavily into electrification, have ZEV requirements in California, and could be greatly disadvantaged by an arbitrary MSRP cap if implemented.

[4] Our associations would oppose any application of MSRP or income caps to the "POP into Electric" program, whether done by resolution or through the governance structure. We believe such action would detract from the program's integrity, and other state programs, using public dollars, have been designed to address equity issues. Moreover, **almost half of the utilities LCFS revenue will be used for equity programs**, including secondary vehicle rebates, and infrastructure benefits, which will address additional market needs beyond the Clean Fuel Reward and should adequately address any potential equity concerns on how to further encourage electrification throughout the state.

(AAMGA2_SF18-3)

Comment: Regarding the specific 2nd 15-Day Changes applicable to the "POP into Electric" program, we support staff's inclusion of minimum percentage contributions for the Clean Fuel Reward for EDUs that opt-in.[5] We believe this is necessary, because it helps to ensure necessary contributions to maximize rebate values; provides certainty and transparency about the revenue available for the rebates; and should provide

assurance to the California Public Utility Commission (CPUC) that this program will provide value for all rate-payers.

[5] We also support that CARB provide the LCFS base credits for EDUs that do not opt-in directly to the program, whether via credit or revenue distribution to the other utilities and/or a 3rd party program administrator. While we understand the impact of these non-opt-in EDUs is minimal, it is nonetheless important to make sure any potential revenue is not left on the table.

(AAMGA2_SF18-4)

Comment: We greatly appreciate the Board's and ARB's vision to work to create additional Clean Fuel Rewards for EVs, using LCFS base residential credit revenue, and we fully support the goal of a statewide, easy-to-implement rebate applied at the time of purchase. We believe this program will and should provide Clean Fuel Rewards to *all* customers that buy or lease an EV, because each of these purchases contributes not only to the future availability of these rebates, but also to the state's goal to reduce petroleum use. We have worked collaboratively and diligently with the utilities to scope out this rebate program, and it is our hope that in the coming months, the program can be started and administered at the earliest possible time and continue annually at a maximum possible rebate value. Transparency, governance, and CPUC support will be critical to the smooth operation of this program, and we appreciate any and all efforts by ARB and the Board to help see through these goals. This program demonstrates how we can all work together to find ways to help grow the electric vehicle market and support the future for a lower carbon transportation fleet. (AAMGA2_SF18-10)

Comment: We are very pleased with the progress CARB, the utilities and automakers have made to develop a point-of-purchase (POP) rebate program and appreciate that the minimum utility contributions after 2022 were raised somewhat from the values presented at the workshop. (UCS4_SF26-2)

Comment: We support the proposed modifications that establish a statewide clean fuel point of purchase (POP) rebate for new electric vehicles that is available to all Californians. The tiered incentive approach for rebates based on battery capacity is beneficial because it appropriately creates more "carrots" for commercializing vehicles that have longer zero-emission ranges.

Increased funding to reduce the incremental cost of electric vehicle (EV) at the point of sale is critical for increasing the number of EVs on California's roads and further advancing the technology. That is because:

1. Vehicle purchase price is one of the top determinants of whether an individual chooses to buy an EV rather than an internal combustion engine vehicle (ICEV).[2]

   [2] See, for example, results of the CVRP survey from ~20,000 customers who bought an EV in California. Available at https://cleanvehiclerebate.org/eng/survey-dashboard/ev

2. New vehicles bought today determine the fleet makeup for the next 10-20 years; whether the vehicle is an EV or ICEV, it typically goes on to secondary customers.
3. Stable, predictable incentives are needed to drive sales, meet California's EV deployment goals, and develop the market for EVs with larger batteries.

The proposed “POP” concept is consistent with the need to incentivize new EV sales today and put more advanced EVs on California’s roads, because it will give consumers an incentive right at the moment when they are considering the new vehicle purchase. And it is a welcome addition to existing funding programs including CVRP and the federal tax credit, which together are vital (though not wholly sufficient) for increasing EV sales.

In that context, we write with one concern. The companies which have done the most to sell EVs to date have begun losing access to the federal tax credit, which comprises the bulk of incentives for light-duty EVs for buyers in California, because they are hitting the statutory cap of 200,000 vehicles.

Tesla has already sold its 200,000th vehicle in the U.S. and begun communicating to customers that its federal incentives will now start phasing down, including for the mid-priced Model 3. General Motors is projected to hit its cap by the end of 2018, and three other automakers are expected to do so within the next 2-3 years.

We encourage the CARB board and staff to consider ways of using the LCFS to additionally support these early movers who are doing the most to put EVs on the road—and who are precisely the ones who are now losing federal support for continuing to do so.

Gasoline consumption has been rising for the past six years in California. Despite all our collective efforts, what we are currently doing is not enough. We need new and creative strategies like the proposal presented here to bend the curve, and to get on a path of decreasing GHG emissions from the light duty vehicle sector. We hope that this is the first of many additional proposals to further incentivize the commercialization of EVs to come.

As always, CALSTART stands ready to partner with CARB towards commercializing EVs and advancing the LCFS. If you have any questions, please do not hesitate to contact me. (CALSTART3_SF44-2)

Comment: PG&E supports ARB’s leadership to create a statewide point-of-purchase (POP) rebate program for EVs funded by the electric distribution utilities’ (EDU) revenues from residential EV charging base credits. This program will provide California consumers with an additional incentive to purchase EVs by providing a rebate at the point of purchase to reduce the upfront cost of the vehicle. In addition, the program will be statewide, allowing for a common offering for all Californians, rather than separate EV incentives within each utility territory. PG&E supports these efforts to accelerate EV adoption across the state. (PGE3_SF49-2)

Comment: CalETC supports the current program design with utilities generating “base” LCFS credits for residential charging and returning the value of those credits to electric vehicle drivers. CalETC and the utilities are committed to continue working with stakeholders and regulators to improve the programs supported by utilities LCFS credit revenue. We share the commitment to accelerate the market for electric vehicles and

support the Administration and Legislature in meeting the state's transportation electrification goals. The utilities are uniquely positioned to work with administration and legislature to invest the LCFS credit value, they are either local public entities, as is the case with publicly-owned utilities, or they are economically regulated, as it is the case with investor-owned utilities. (CALETC4_SF50-3)

Comment: We support redirecting funds from the residential EV charging pathway of the LCFS to a statewide, point-of-sale rebate program for new EV buyers. (COLTURA2_SF52-2)

Comment: Specifically, SCE supports the changes that provide a framework for the development of point-of-purchase EV rebates. For example, returning the multi-unit dwelling credits to electric distribution utilities increases the size of the rebates, and providing basic rules on the rebates makes implementation more feasible. A point-of-purchase EV rebate program will be very beneficial to continuing to accelerate EV adoption in California. SCE also agrees with the CalETC comments on the second round of 15-day LCFS modifications that support the point-of-purchase EV rebate provisions and other improvements to the LCFS regulation (e.g., improving the California statewide grid average carbon intensity calculation for electricity and expanded requirements for load serving entities). (SCE2_SF53-3)

Comment: Envoy supports point-of-purchase rebates in concept, as a tool to accelerate transportation electrification. The proposed point-of-purchase program will leverage existing core competencies (e.g., utility-based LCFS credit management, rebate management, others) which may streamline access to rebate programs, leading to reduced costs and increased benefits. In addition, the point-of-purchase program will join a volume of existing rebate programs, which under certain conditions can provide up to $14,000 to entice ZEV adoption.[2]

[2] *Incentives are available across three programs, Enhanced Fleet Modernization Program (EFMP), EFMP Plus-Up, and Clean Vehicle Rebate Project (CVRP) — all of which can be stacked. Household Income (≤ 225% FPL) are eligible to receive up to $14,000. Website Access: https://www.arb.ca.gov/msprog/aqip/efmp/efmp.htm*

(ENVOY2_SF55-2)

Comment: SMUD supports the proposed point-of-purchase program.

SMUD supports the addition of the point-of-purchase (POP) rebate program and the contribution percentages outlined on pages 48-49. SMUD believes that upfront buy-down incentives can be an effective tool to increase electric vehicle market adoption. SMUD currently uses a portion of the residential-based LCFS credits we are awarded in a similar fashion—to support our "free fuel for 2 years" program. We view the POP rebate as an effective way to achieve the same objective—by moving the incentive to the time of purchase, you have the highest likelihood of impacting customers' purchase decisions. We believe this will have a greater positive effect on the buyer's decision to choose an EV versus other options previously considered. (SMUD3_SF59-4)

Comment: Board Resolution 18-17 instructed staff to work with stakeholders to develop a method for using LCFS credits from unmetered residential charging to support a state-wide EV rebate program. **NextGen strongly supports the creation of a state-wide point-of-purchase EV rebate program.** We appreciate the efforts of staff, Vice-Chair Berg and stakeholders from utilities and automakers towards developing a workable statewide rebate which will more efficiently leverage LCFS credit value into support for broader EV deployment. (NEXTGEN4_SF60-3)

> **Agency Response:** Staff acknowledges the commenters' support for amendments designed to accommodate a statewide point-of-purchase rebate program being developed by utilities. Please see Response D-25a in Chapter IV.
>
> In regards to equity component in the rebate program, Board Resolution 18-34 directed the Executive Officer to work with stakeholders to establish an equity-based framework for the possible uses of base credit value from residential charging, consistent with legislative priorities. The Board also directed staff to continually evaluate such provisions and propose adjustments as needed. Staff did not propose any specific provisions or measure to address equity in the regulation. Staff intends to continue stakeholder engagement to determine if additional considerations are necessary for early movers as the utilities design the rebate program.
>
> In regards to the comment about credits for EV charging at multi-family residences in SCE2_SF53-3, please refer to Response D-15a. in Chapter IV, Proposed Credit Generator for Multi-Family Residential EV Charging.

D-6.13c. Multiple Comments: ***Proposed Utility Contributions for the Statewide Rebate Program***

Comment: However, to ensure the success of the "POP into Electric" program to meaningfully drive PEV adoption to further the state's clean transportation goals, we recommend higher percent contributions by the utilities and recommend the following minimum contributions by the utilities:

EDU Category	% Contribution
IOU	80%
Large POU	55%
Medium POU	20%
Small POU	0%

If ARB does not increase the minimum contribution in the current rulemaking, we encourage ARB to investigate increasing these contributions in future rulemakings.

The current minimum percent contributions for Clean Fuel Reward will result in a substantial portion of LCFS residential charging revenues, approximately 41%, being

diverted out of the “POP into Electric” program. While we prefer a higher percent contribution into “POP into Electric,” it is our understanding that the utilities are requesting to withhold this portion of revenue to fund important and necessary equity programs in addition to the Clean Fuel Reward, providing more value to all customers in the state and ensuring that this revenue source meets the state’s equity needs. (AAMGA2_SF18-5a)

Comment: LADWP is committed to reducing GHG emissions pursuant to AB 32 and SB 32, and to contributing efforts to meet the Governor's Executive Order B-48-18 goal of 5 million zero emissions vehicles by 2030. LADWP shares the same common vision and goal as other stakeholders (utilities and automobile manufacturers) of building and transforming the transportation sector to electric in order to reduce emissions and benefit the public. There are many pathways to reaching this goal. LADWP believes that ARB's proposal for a percentage contribution of base credits from EDUs to the statewide point-of-purchase rebate will be a good compromise between all stakeholders to meet this common goal. LADWP supports ARB's proposal that large publicly-owned utilities contribute 35 percent of its base credits toward the point-of-purchase rebate. This percentage would allow LADWP to retain sufficient funding to continue its transportation electrification efforts that will benefit its customers.

LADWP's key programs include:

- Residential Programs
  - Used Electric Vehicle (EV) Rebate; EV Charger Rebate; Smart Charging Rebate Demonstration
- Commercial Programs
  - EV Charger Rebate; Pilot Program to Install EV Chargers at the Los Angeles Unified School District Facilities; Metro Electrification (Orange Line)
- City Programs
  - Public and Workplace Charger Installations; Los Angeles Department of Transportation Bus Electrification; Port of Los Angeles Electrification Infrastructure; Public Charging Plazas and EV Car Share in Disadvantaged Communities
- Education/Outreach
  - Customer Events; Customer and Dealer Programs (LADWP3_SF42-3)

Comment: PG&E does, however, have concerns about the disparity between the level of LCFS credits contributed by investor-owned utilities (IOU) and large publicly-owned utilities (POUs). PG&E believes that the IOUs and large POUs should contribute the same share of their respective credits (or revenues) to the statewide POP program.[1] This would ensure that all Californians can equally benefit from the residential LCFS credits that are managed by the states’ EDUs. PG&E notes that the Executive Officer will provide recommendations to the Board “for further increasing utility contributions to the point-of-purchase rebate program,” by January 1, 2025. PG&E recommends that

the Board clarify that the intent of these recommendations is to ensure that IOUs and large POUs contribute the same percentage (67%) of their LCFS credits or revenues as soon after 2025 as possible.

[1] PG&E recognizes that the revenues generated by medium and small POUs residential LCFS credits are relatively small and administration of those funds could represent a substantial share of those revenues. As a result, a smaller contribution share for those entities may be appropriate.

(PGE3_SF49-3)

Comment: Recommendation: Utilities should contribute as much as possible into the rebate program, ideally 100% of the residential pathway funds, as this is the most effective way to drive EV sales. Under the current proposal, which holds back ~40% of the funding for other utility programs, stakeholders have little visibility into how those funds will ultimately be used, and there is a strong belief among stakeholders that the money would be better deployed at the point of sale. (COLTURA2_SF52-3b)

Comment: SMUD is also supportive of the POP program percentage contributions proposed in the Second 15-day Modifications for the different EDU classes. SMUD currently funds a host of measures with our awarded LCFS credits that we have found advance EV market adoption by our customers and return value back to them, with major environmental and community benefits. We find it critical that EDUs continue to use their LCFS credits, in part, for a variety of programs that support market transformation of the mass automotive market.

In addition to the upfront rebates we currently offer, SMUD also currently uses the LCFS residential credits we are awarded to support: charging infrastructure deployment, public outreach and education, dealer engagement, and on-line tools like an EV-bill calculator. All of these measures are targeted toward increasing residential plug-in electric vehicle (PEV) sales and reducing GHGs by transforming our customer's fuel usage from petroleum to clean electricity. We also strongly believe that our infrastructure deployment activities are enabling customers in disadvantaged communities and multi-family residences to approach EV ownership. These customers have been shown to have higher barriers to EV adoption because they often do not have access to other forms of charging infrastructure. SMUD views outreach and education as a critical piece of our strategy to increase awareness around PEVs by supporting potential EV buyers with information and motivating them to consider PEVs through ride-and-drive opportunities. These events allow customers to experience electric drive propulsion and the benefits of electricity as a clean fuel.

SMUD recognizes that many of the details around a statewide POP rebate program have yet to be developed. We stand ready to support those development activities and are committed to working together with CARB, our fellow utilities, and the EV industry to ensure the success of this important program. (SMUD3_SF59-5)

Comment: That said, we are still concerned that the minimum percentage contribution of base credits for residential electric vehicle charging (or net base credit proceeds) by publicly-owned utilities (POUs) is too low (§ 95483 (c)(l)). Our understanding is that the POUs' percentages won't be phased up until 2023, and even by then, will not come into parity with the investor-owned utilities' (IOUs) minimum contribution requirements. We

appreciate ARB's recognition of this disparity and any efforts you can still do to reduce it. (CPUC1_SF64-4)

> **Agency Response:** Please see Response D-6.25e in Chapter IV and Response D-6.13b in this chapter.

D-6.13d. *Proposed Rebate Amount Tiers Based on Rated Battery Capacity*

Comment: § 95483(c)(1)(A)(2) establishes a formula for scaling the proposed incentive in relation to battery size. This is intended to provide an incentive for automakers to deploy vehicles with larger, and more capable batteries. We support the intent behind this provision, however we note that threshold level for receiving a full incentive is set at 16 kWh, which is significantly smaller than the batteries deployed in almost every current-generation electric vehicle and even smaller than the battery in some plug-in hybrids. **We suggest that CARB increase the ratio of battery size to incentive amount over time.** We recognize that this schedule was set to harmonize with Federal battery rebate programs and agree that there is value in such harmonization, but feel that maintaining an incentive to increase battery size is a higher priority. Insofar as the Federal incentive may not effectively support larger battery sizes needed to deploy a more robust and capable fleet of electric vehicles, California should choose to adopt a more effective standard. (NEXTGEN4_SF60-8)

> **Agency Response:** Staff agrees with the commenter that it is valuable to promote plug-in electric vehicles with greater all-electric range and larger battery packs. So far, the existing utility rebate programs have not differentiated by EV's rated battery capacity and this is a missed opportunity to promote costs decline in EV battery technology.
>
> Staff believes any statewide rebate funded by LCFS proceeds can help advance battery technology in-line with the technology advancement goals of the program. For simplicity, at the outset of any statewide rebate program, staff proposed the statewide rebate mirror the structure adopted for Plug-In Electric Drive Vehicle Credit also known as the federal EV tax credit, which is a sliding scale based on the rated battery capacity of EV. This structure is well understood by the auto dealers and a statewide rebate program based on the same principal could be easily integrated to the EV sales pitch and marketing materials. Staff will continue to evaluate the success of statewide rebate programs in promoting EVs and is committed to working with stakeholders to update the requirements in future rulemakings to provide appropriate signals for EV adoption.

D-6.13e. *Proposed Tiers Based on Rated Battery Capacity*

Comment: The definition of "battery capacity" as specified in § 95483 (c) (1) (A) (2) is unclear as to whether it refers to the sum of all battery cell capacity installed within the vehicle, the maximum possible capacity of the installed battery system, or the capacity available for use by the vehicle under its default operational condition. This distinction is important because one tool battery makers employ to maximize the lifespan of

batteries is to limit or prevent charging or discharging behavior which would put the battery into its highest and lowest charge states. This puts some fraction of the battery's nominal capacity off-limits to the vehicle's charge controller and yields a battery with a smaller functional capacity, but enhanced durability.

We suggest clarifying the definition of "battery capacity" as applied in § 95483 (c) (1) (A) (2) to refer to the effective capacity available to the vehicle, under its default mode of operation. Doing so will ensure that battery manufacturers cannot increase the state subsidy available to them without increasing the effective range of the vehicle in question. (NEXTGEN4_SF60-9)

> **Agency Response:** Staff proposed a framework to calculate the rebate amount for an electric vehicles under statewide point-of-purchase clean fuel rebate program that is based on the vehicle's rated battery capacity. Staff proposed to use the rated battery capacity as all EV models are marketed with manufacturer rated battery capacity that is verifiable and could be easily used for calculating rebate amounts at the point-of-purchase. Staff agrees that the rated battery capacity may not be same as the functional battery capacity, but not all EV manufacturers publish functional battery capacity ratings based on a consistent methodology.

D-6.13f. *CPUC Approval for Implementation Statewide Point-of-Purchase Rebate Program*

Comment: While we understand that the program's start date is reliant on CPUC approval, as noted in ARB's proposed regulatory text, it is not clear why CPUC approval is needed. Current CPUC guidance allows the IOUs to provide vehicle rebates with this revenue using 100% of the revenue.[7] Based on past CPUC proceedings that have lasted several years, we are concerned the "POP into Electric" could be unnecessarily delayed. Consequently, we recommend ARB revise the regulations to reassign the LCFS Base Residential EV Charging credits no later than March 2020, if the "POP into Electric" has not started by December 1, 2019. Additional consideration of equity programs and changes to revenue contribution can occur in parallel through the CPUC process, without impacting the start date of the "POP into Electric" program.

[7] CPUC guidance clearly states that the funding generated by IOUs must be returned to EV customers in the form of a rebate: "…we will permit each utility to choose between an annual credit and a one-time upfront rebate." ("DECISION ADOPTING LOW CARBON FUEL STANDARD REVENUE ALLOCATION METHODOLOGY FOR THE INVESTOR-OWNED ELECTRIC AND NATURAL GAS UTILITIES," p. 30). While any deviation from these authorized uses would require additional CPUC approval, the CPUC has already allowed for 100% of the IOUs' LCFS revenue to be used as a "one-time upfront rebate".

Our associations recommend that this program start no later than six months after the effective date of the regulation, and we hope that the Board can provide resolution language that puts in place a goal to implement within six months, understanding that there are a number of critical factors, like CPUC support, that could delay implementation. It is also important for the Board's resolution to include direction to work with the CPUC to determine how best to implement the program in a timely manner. This direction is consistent with the Board members' desire to see an

expeditious implementation of the program and is reasonable considering EDUs, most of which already have rebate programs in place, will have had over a year since the April board hearing to implement a program. (AAMGA2_SF18-6)

> **Agency Response:** California Public Utilities Commission (CPUC), in decision D.14-12-083, established criteria and provided the investor-owned utilities (IOU) some options for returning the value of LCFS proceeds to the current and future EV drivers. IOUs may have to file a request with CPUC to participate and start contributing to a statewide point-of-purchase rebate program. Therefore, staff proposed that an opt-in utility, or its designee, generating base credits for residential EV charging must start contributing to the statewide rebate program upon CPUC approval of the three currently opt-in IOU's – Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric – filings to initiate a statewide point-of-purchase rebate program. This would ensure all opt-in utilities, including IOUs and Publicly-owned Utilities (POU) which are not regulated by CPUC, start contributing to the statewide rebate program at the same time.
>
> Staff did not propose specific timeline for the start of statewide rebate program as it understands all the CPUC and IOUs would have to follow the due process for designing and implementing a well thought-out statewide rebate program and did not wanted to set unrealistic expectations that could conflict with CPUC's process or hinder prospect of an effective rebate program.

D-6.13g. ***CPUC Approval for Implementation Statewide Point-of-Purchase Rebate Program***

Comment: 2. Statewide Point of Purchase Rebate – We request clarification that CARB' s modified regulation does not limit the distribution of an IOU's LCFS credit proceeds (or credits) to customers in its own service territory. Specifically, we request that CARB make clear – if this is its intent – that the new regulation does not preclude the statewide program administrator from distributing an IOU's LCFS proceeds (or credits) outside the IOU's service territory.

…

The CPUC's decision (D.)14-12-083,[1] adopts a methodology for allocating revenue to plug-in electric vehicle (PEV) customers from the sale of LCFS credits by the electric and natural gas investor-owned utilities. In this decision, the electric IOUs are directed to allocate LCFS credit revenue to PEV customers by reducing the purchase cost of a PEV or by applying the revenue as a credit against the customer's electric utility bill annually.

[1] http://docs.cpuc.ca.gov/PublishedDocs/Published/GOOO/M143/K640/143640083.PDF

The decision allows a one-time rebate to be provided to customers in an IOU's territory by noting, "A one-time rebate can achieve equitable distribution to all PEV drivers. Unlike a rate reduction that depends on PEV customers using PEV rates, a one-time rebate can be provided to every driver that buys or leases a PEV insofar as a utility

successfully engages the PEV distributors in its service territory to help make customers aware of the rebate." In reaching this conclusion, the decision cited CARB's LCFS Regulation § 95484(a)(6)(B)-(D) as authority, stating the electric utility is eligible to opt in as the regulated entity for their service territory to generate LCFS credits for residential customers. (D.14-12-083 at 37.)

In CARB' s proposed second 15-day modifications, it appears that all language that could have been interpreted to limit the distribution of an IOU's LCFS credit revenue (or credits) to its own service territory has been eliminated. This includes § 95484(a)(6)(B)-(D), which does not appear in the proposed regulation. Further, the requirement for a utility to engage the public or PEV distributors in order to generate credits has been eliminated. We agree with striking all of this language if the intention is to move toward statewide distribution of the utility LCFS revenues.

To assist the CPUC in implementing a statewide POP rebate, CPUC asks the CARB to clarify that the modified LCFS regulation does not limit the distribution of an IOU's LCFS credit revenue (or credits) to customers in the IOU's own service territory. Since the foregoing decision cited the CARB regulation as requiring service-territory specific distribution, the CPUC requests clarity that elimination of the regulation means such distribution is no longer required. The CPUC requests that CARB make clear – if it is CARB's intent – IOUs are servicing the customers in their own territory by giving LCFS proceeds (or credits) to a statewide program administrator. (CPUC1_SF64-6)

> **Agency Response:** In section 95491(d)(3)(A)2., staff proposed a change to clarify that a Load-serving Entity (LSE), including Investor-owned Utilities (IOU), generating credits must use all credit proceeds to benefit the current or future EV drivers across California and not just within its service territory. Staff would like note that the intent of the proposed change is to allow opt-in utilities to use the LCFS proceeds for a statewide point-of-purchase rebate program.

D-6.13h. ***CPUC Approval for Implementation Statewide Point-of-Purchase Rebate Program***

Comment: Finally, we want to clarify the CPUC's timeframe for implementing any new LCFS regulation. In the best case, IOUs will file updated advice letters with the CPUC's Energy Division. Given the nature of the program, we expect protests and responses from external parties and some additional questions from our Energy Division analysts. Resolution of advice letters can take 6 months or more. Also, depending on additional updates to the regulations, including whether or not the utilities will be the contract holders for the new statewide administer of the POP program, the original proceeding may need to be reopened which will be a longer process. (CPUC1_SF64-7)

> **Agency Response:** Staff appreciate the clarification provided by the commenter as it relates to the CPUC's due process for approving participation of IOUs in a statewide point-of-purchase rebate program and the expected timelines for the process.

D-6.13i. ***Implementation Details of Statewide Point-of-Purchase Rebate Program***

Comment: We are pleased that the agency has committed to making the POP rebate work, and we appreciate all staff efforts to scope and assist in developing the framework for this program. There are still, however, a number of critical aspects to this program that must be sorted out following implementation of the program, and ongoing support from ARB is needed to help get this program started as expeditiously as possible. These efforts include CPUC support to move forward, development of a transparent process for rebate designations, and supporting the utilities in getting a governance structure and 3rd party administrator in place to oversee the program.[6]

[6] There are a number of uncertainties still surrounding implementation of the "POP into Electric" program that may impact its success. One of the key unknown elements is the governance structure for the group that implements the rebates. Our associations believe that the governance structure needs to be robust and transparent to ensure success of the program and a maximum rebate level. We also understand that the utilities want some assurance that they can continue to earn residential credits and run the "POP into Electric" program for an unspecified period of time. We agree the utilities will undertake a significant effort in getting the rebates up and running, and we appreciate that they would like some certainty surrounding the program. Our associations therefore recommend Board Resolution language that assures utilities can earn these credits for three years following the effective date of the regulation. We believe this language will encourage all parties to work quickly to implement the program and provide additional encouragement for the program to operate smoothly, easily and at the maximum rebate levels. If for some reason this does not occur, then any potential regulatory amendments to reassign credits would not occur before three years after the effective date of the regulations.

(AAMGA2_SF18-5b)

Comment: Many details of this program are yet to be decided, and we urge CARB and the utilities to expeditiously develop a governance structure that gets rebates to EV buyers as quickly as possible and establishes a high level of accountability and transparency to ensure that program funds are being used to fund as large a rebate as possible. The governance structure should ensure that all key stakeholders have a voice, not just utilities and automakers but also public interest organizations that have expertise in EV regulation and incentive programs to represent the interests of EV buyers and drivers, as well as the broader community impacted by transportation pollution. (UCS4_SF26-3)

Comment: CalETC is supportive of the utilities' efforts, working with CARB, the automakers and other stakeholders, to design and implement a point-of-purchase Clean Fuel Reward. We have very much appreciated, and the efforted has benefited tremendously from, the work Vice Chair Berg has done to organize and facilitate the Clean Fuel Reward effort. CalETC also notes that many details of the future Clean Fuel Reward are appropriately reserved for a future governance agreement between select EDUs and the CARB Executive Officer. (CALETC4_SF50-5)

Comment: <u>Implementing the program quickly</u>: Automakers, dealers and many other stakeholders agree that a statewide, point-of-sale rebate is far more effective than the current, fragmented rebate programs available today in certain utility service territories. While we are pleased that the utility coalition has proposed a statewide program, we still have little visibility into the rebate amount or timing as to when the program would be launched. We believe a meaningful statewide rebate should be made available to

consumers as quickly as possible, and certainly no later than mid-2019. (COLTURA2_SF52-3a)

Comment: Envoy requests clarification regarding the amount to be provided under the point-of-purchase rebate program, and encourages CARB to work with stakeholders to set this amount as expeditiously as possible to avoid confusion. In addition, to encourage expanded market innovation, Envoy recommends that CARB ensure that EV fleet mobility service providers (such as Envoy) have access to these rebates. More broadly, Envoy encourages CARB work with stakeholders to evaluate innovation opportunities with LCFS funds beyond the point-of-purchase rebates model, specifically with the revenue generated from LCFS credits that have not been earmarked for point-of-purchase rebates (see innovation discussion in "Sister Agencies" section below). (ENVOY2_SF55-3)

Comment: We support the ongoing efforts by EV manufacturers, utilities and other stakeholders to develop a comprehensive, statewide point-of-purchase EV rebate. We feel that selecting an independent third party, subject to oversight by CARB, is the most appropriate structural choice for such a program. We can draw from lessons learned in the oversight of the Clean Vehicle Rebate Program as we design this new LCFS-funded rebate.

We support the proposal to have stakeholders seek approval with CPUC to modify existing rules governing the use of LCFS revenue to allow the creation of a single, statewide program to issue rebates for EVs, funded by value from un-metered residential EV charging credits. We are concerned that the necessary administrative and stakeholder engagement processes to develop and adopt the necessary rules or to amend existing rules will be time-consuming and result in a significant delay before the program becomes operational. We urge CARB to work with all stakeholder to expedite this process to the greatest possible degree, to ensure that the rebates envisioned by this are made available to prospective vehicle purchasers as quickly as possible.

As utilities transition the operation of EV rebates from their own programs to the state-wide alternative envisioned by these amendments, it is important that CARB and other state agencies exercise their full oversight authority over the funds which support point-of-purchase rebates and also the funds which utilities retain for their own projects. With multiple funding streams supporting the deployment of EV charging infrastructure, including recent PUC proceedings, Volkswagen settlement funds, GGRF revenue, CEC grants, etc., it is critical that CARB work with other state agencies to ensure that infrastructure funding is spent in an efficient and non-duplicative manner. (NEXTGEN4_SF60-4)

> **Agency Response:** Staff appreciates the commenters' recommendations for implementation of the statewide point-of-purchase rebate program but note that details like start date, amount of rebate, eligibility of fleets for the rebate, details on the third-party administrator are beyond the scope of this rulemaking.

The utilities, automakers, and dealerships have been engaged in ongoing discussions to determine the details for the implementation of the statewide rebate program. The start date would depend on the CPUC's approval of IOUs participation in the statewide rebate program. Stakeholders have been modeling various scenarios to determine an expected range of rebate amounts but that depends on several variables including but not limited to the starting balance for the rebate program, rate of EV adoption, and rebate's take-up rate. In addition, a Governance Agreement signed by the utilities and the Executive Officer will include the principles and operational details for the governance structure, transparency, and accountability for the rebate program among other details.

In regards to equity component in the rebate program, Board Resolution 18-34 directed the Executive Officer to work with stakeholders to establish an equity-based framework for the possible use of base credit value from residential charging, consistent with legislative priorities. The Board also directed staff to continually evaluate such provisions and propose adjustments as needed. To follow this direction, staff will engage stakeholders to develop a comprehensive equity-based framework for the incentive programs funded by the base credits.

D-6.13j. Multiple Comments: ***Using LCFS to Promote ZEV Adoption in Disadvantaged and Low-Income Communities***

Comment: Improving EV affordability equitably: There has been a variety of proposals regarding how to address equity in the proposed use of these funds. An income or MSRP cap on the rebate, for example, have been discussed as potential options. These options, however, would add further complexity to the sales process, as dealers and salespeople would have to explain both the MSRP cap as well as the Clean Vehicle Rebate Project ("CVRP") income cap to customers at the point of sale.

- Recommendation: California has already selected an approach to address equity through the income cap levels in the CVRP. We recommend that CARB use the LCFS funding that is currently being set aside for other utility programs (~40%) to fund a bonus incentive for low-income buyers based on the same income levels as the CVRP program. This will dramatically simplify and clarify the sales process, as sales teams can communicate one set of income limits to consumers. Administration of the program will also be greatly simplified, as the administrator of the LCFS rebate program can coordinate with the CVRP administrator to attach the LCFS bonus check onto the CVRP rebate. (COLTURA2_SF52-4)

Comment: Helping support EV deployment in disadvantaged communities is especially important, revenue from LCFS credits can help fill critical gaps in other programs. **We urge CARB to focus the LCFS credit value retained by utilities towards projects which support EV deployment in disadvantaged communities, and require transparent accounting of the disposition of those funds.** (NEXTGEN4_SF60-5)

Agency Response: Staff agrees that addressing equity while designing programs to promote EV adoption is extremely important, and believe that utilities are well suited to support EV adoption in disadvantaged and low-income communities. Some utilities are already supporting programs focused on disadvantaged communities.

For details on CARB's commitment to equity outcomes in future implementation of the LCFS to promote ZEV adoption, please also see Response D-6.13b in this chapter.

E. Regulated Entities

E-1. *Support for Designee as an Opt-in Entity*

Comment: Envoy supports the Proposed Regulation Amendments hierarchy,[1] which will allow for Electrical Distribution Utility (EDU), or designees, to accrue and sell credits on the EDU's behalf. Allowing parties other than EDUs to serve in this manner may lead to cost savings, create innovative management approaches, and may spur market opportunities and unique partnerships. This approach may also be of added value to EDUs, that may face expanded program complexity under the revised program requirements.

[1] The Proposed Regulation Amendments State that: "the EDU or its designee is the credit generator for base credits for the portion of residential EV charging", and that "The EDU may authorize a third party to sell the EDU's credits." Page 47; Website Access: https://www.arb.ca.gov/regact/2018/lcfs18/15dayatta2.pdf.

(ENVOY2_SF55-1)

Agency Response: Please refer to Response E.1 in Chapter V.

F. Average Carbon Intensity Requirements and Fuel Availability

F-1. *Support for the Proposed 2030 Target*

Comment: We support the 2030 target for reducing the carbon intensity of transportation fuels by 20%. This target is achievable by continuing the growth of alternative fuels. The LCFS will make a major contribution to California's efforts to reach its 2030 standard of reducing greenhouse gas emissions by 40% from 1990 levels by 2030. In addition, a strong LCFS will reduce the localized air pollution, caused primarily by combustion of fossil fuels for transportation, that continues to damage the health of millions of Californians. (CCAALACVAQ1_SF16-3)

> **Agency Response:** Staff appreciates the support for the proposed changes to the 2030 CI target.

G. Credit and Deficit Provisions

G-1. *Support for the Proposed Credit and Deficit Provisions*

Comment: PG&E appreciates ARB's clarification that the "date" on all anticipated deliveries is the "expected date" and may not be the actual date of transfer (§95487(b)(1)(D)(5)). (PGE3_SF49-10)

Agency Response: Please refer to Response G-1 in Chapter V.

G-2. Multiple Comments: *LCFS Implementation*

Comment: PG&E continues to request clarification from ARB on how the Credit Seller and Credit Buyer should coordinate on initiating and completing the transfer request in the Credit Transfer Form (CTF) provided in the LCFS Reporting Tool and Credit Bank & Transfer System (LRT-CBTS), as described in §95487(b)(1)(C-E). In ARB's existing regulation, the responsibilities of the Credit Seller to the Credit Buyer are explicit on the handoff between releasing the credit transfer, and confirming the credit transfer. While the proposed timing on the transfer and confirmation would change based on the draft amendments to the regulation, stating that "the Seller and the Buyer must initiate and complete the transfer request" (Type 1) or "must report the following" (Type 2), leaves confusion and duplicative responsibilities. This could lead to unnecessary correction requests requiring review and approval by the Executive Officer. ARB should provide clear instructions (similar to the existing regulation) on how the responsibilities should transition from Seller to Buyer to complete the transaction. (PGE3_SF49-9)

Comment: However, PG&E recommends that ARB also provide clear instruction on completing Type 2 transfers. The proposed regulation only addresses reporting the transaction within 10 days of the Date of Transaction Agreement and provides no information on the requirements or process for completing the transfer or amending the report in the LRT-CBTS. Additionally, PG&E recommends ARB provide clarity around any consequences or additional processes that could result if the credit delivery timing described in §95487(b)(1)(B)(1-2) for Type 1 and Type 2 transfers is not adhered to by one or both parties.

Considering that the implementation of a new Credit Transfer process between Parties, and the ability to transfer credit through an authorized clearing service provider, will change existing processes, PG&E requests that ARB conduct workshops to demonstrate the end-to-end process in the LRT-CBTS for each Type of Transfer listed in §95487(b)(1)(B). These workshops should be held in early Q4 2018 to allow regulated entities adequate time to ensure revised internal processes are in place prior to 2019 implementation. (PGE3_SF49-11)

Agency Response: Please see Response W-1.7 in Chapter V.

H. Buffer Account

No comments on this topic were received during the 2nd 15-day comment period.

I. Infrastructure Crediting

I-1. *Support for the Modifications to the Proposed Infrastructure Crediting Provisions*

I-1.1. Multiple Comments: *Support for the Modifications to the Proposed Infrastructure Crediting Provisions*

Comment: We are strong supporters of the ***Hydrogen Refueling Infrastructure*** (HRI) Pathway as proposed by the California Air Resources Board (CARB). (AL2_SF1-1)

Comment: We support the ***Hydrogen Refueling Infrastructure*** (HRI) Pathway as proposed by the California Air Resources Board (ARB) in the [Date] 15-day Notice of Public Availability of Modified Text and Availability of Additional Documents and Information for Proposed Amendments to the Low Carbon Fuel Standard (LCFS) Regulation and to the Regulation on Commercialization of Alternative Diesel Fuels (ADF) (henceforth "15-day Notice"). The reasons for this support have been articulated in prior letters to the docket.

The HRI pathway as proposed is an effective incentive for expanding zero-emission vehicle infrastructure while remaining consistent with the LCFS policy's intent.

We believe the HRI as proposed by the ARB is consistent with Executive Order B-48-18 and the LCFS policy intent. The LCFS was established by Executive Order S-01-07, pursuant to AB32, to reduce the carbon intensity of California's transportation fuels. With Executive Order B-48-18, California announced a target of 5 million ZEVs by 2030 and an eight-year $2.5 billion investment initiative to continue the state's clean vehicle rebates and spur more infrastructure investments. The Executive Order also specifically calls for State entities to collaborate with stakeholders to implement this order, including "expand zero-emission vehicle infrastructure through the Low Carbon Fuel Standard Program."

Reaching California's goals for greenhouse gas and criteria pollutant emission reductions necessitates the acceleration and scaling up of very low-emission options in the transportation sector. This will require consumer choice across all vehicle segments and refueling/recharging modes of use, and will require growth in California's energy infrastructure to accommodate demand from the transportation sector as well as increasing supply from renewable sources. To be successful, a portfolio of ZEV including FCEV, Battery Electric Vehicles (BEV) and Plug-in Hybrid Electric Vehicles (PHEV) will be needed. Of these, FCEVs have the benefit of long range, fast refuel time and scalability, and are a very good ZEV option for those without the ability to charge at home. The refueling model for FCEVs is like that of conventional internal combustion engine vehicles in that it is done at a refueling station. As such, hydrogen refueling station capacity, coverage, and cost are prerequisites for a successful FCEV market. At the same time, retail hydrogen fueling stations does not benefit from an extensive existing infrastructure it can leverage (e.g., electrical transmission, natural gas pipelines, liquid hydrocarbon fuel distribution assets) in the same way that other

alternative fuels do. The initial low utilization of new refueling infrastructure during early stages of the market limits the pace of development and availability of this fuel, and increases the cost relative to traditional transportation fuels, all of which inhibit customer adoption. However, with modest scale in sustained development of hydrogen refueling infrastructure, it has been shown that the cost of hydrogen refueling stations can be reduced by 50% or more. A significant portion of cost reduction in hydrogen refueling stations serving light-duty vehicles can transfer to stations serving heavy-duty vehicles. Therefore, it is our conclusion that it is appropriate and makes sense to take additional action within LCFS to help accelerate the investment and buildout of retail hydrogen fueling stations.

We believe the HRI has benefited from public input during the workshop process and produced a stronger rulemaking as a result. The following list highlights ways in which updates to the HRI Pathway Rules, as written, will effectively accomplish the program's goals, and it provides input for LCFS staff to consider which could help further assure that the HRI effectively meet its intended results: (H2IND3_SF6-1)

Comment: We support the ***Hydrogen Refueling Infrastructure*** (HRI) Pathway as proposed by the California Air Resources Board (ARB) in the August 13, 2018, 15-day Notice of Public Availability of Modified Text and Availability of Additional Documents and Information for Proposed Amendments to the Low Carbon Fuel Standard (LCFS) Regulation and to the Regulation on Commercialization of Alternative Diesel Fuels (ADF) (henceforth "15-day Notice"). The reasons for this support have been articulated in prior letters to the docket.

The HRI pathway as proposed is an effective incentive for expanding zero-emission vehicle infrastructure while remaining consistent with the LCFS policy's intent.

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charge at home. The refueling model for FCEVs is like that of conventional internal combustion engine vehicles in that it is done at a refueling station. As such, hydrogen refueling station capacity, coverage, and cost are prerequisites for a successful FCEV market. At the same time, retail hydrogen fueling stations does not benefit from an extensive existing infrastructure it can leverage (e.g., electrical transmission, natural gas pipelines, liquid hydrocarbon fuel distribution assets) in the same way that other alternative fuels do. The initial low utilization of new refueling infrastructure during early stages of the market limits the pace of development and availability of this fuel, and increases the cost relative to traditional transportation fuels, all of which inhibit customer adoption. However, with modest scale in sustained development of hydrogen refueling infrastructure, it has been shown that the cost of hydrogen refueling stations can be reduced by 50% or more. A significant portion of cost reduction in hydrogen refueling stations serving light-duty vehicles can transfer to stations serving heavy-duty vehicles. Therefore, it is our conclusion that it is appropriate and makes sense to take additional action within LCFS to help accelerate the investment and buildout of retail hydrogen fueling stations.

We believe the HRI has benefited from public input during the workshop process and produced a stronger rulemaking as a result. The following list highlights ways in which updates to the HRI Pathway Rules, as written, will effectively accomplish the program's goals, and it provides input for LCFS staff to consider which could help further assure that the HRI effectively meet its intended results: (H2IND4_SF7-1)

Comment: We also support the changes for the Fast Charging Infrastructure (FCI) and Hydrogen Refueling Infrastructure (HRI) pathways. (AAMGA2_SF18-2)

Comment: We continue to support the inclusion of FCI and HRI pathways, and we recommend adoption of these provisions, including the proposed 2nd 15-day changes. (AAMGA2_SF18-8)

Comment: To align with the Governor's Executive Order B-48-18 of 10,000 direct current fast chargers (DCFC) by 2025, the City of Los Angeles' contribution is estimated to be approximately ten percent of that goal at 1,000 DCFC. LADWP supports ARB's concept for infrastructure crediting for the purpose of incentivizing early-stage infrastructure buildout. LADWP supports the proposed changes outlined in the Second 15-day Modification. (LADWP3_SF42-6)

Comment: PG&E supports California's policies that advance hydrogen and electricity as clean transportation fuels. PG&E recognizes the need for publicly accessible zero-emission vehicle infrastructure, and the challenges associated with making investments in alternative fuel stations at this early phase of the market. Expansion of zero-emission vehicle fueling infrastructure, like DC fast chargers and hydrogen (H2) stations, will help accelerate the market for both fuel cell and battery-electric technologies, and make refueling more accessible to California residents who do not currently have access to home charging or a nearby hydrogen station.

ARB Staff's proposal for capacity crediting programs for DC fast chargers and H2 stations is an innovative approach to incentivize additional clean transportation infrastructure. (PGE3_SF49-6)

Comment: *The Revised Cap on Aggregate HRI and FCI Credits Will Effectively Support the Intent of the Program.*

The First 15-Day Package of amendments introduced the Hydrogen Refueling Infrastructure (HRI) and Fast Charging Infrastructure (FCI) provisions, per the Board's instruction in Resolution 18-17. That proposal included a provision which restricted the acceptance of applications to the program when HRI or FCI credits exceeded 2.5% of total LCFS deficits. As we discussed in our July 5th comment letter, the initial proposal would not achieve the stated goal of limiting credits to the specified level. Staff's revised version in the current proposal, creates an effective and binding cap on total infrastructure credits and provides much greater certainty that infrastructure credit issuance will not exceed the intended cap. **We support adoption of the cap on capacity credits, as described in § 95486.2 (a) (3) (A) and § 95486.2 (b) (3) (A) in the current proposal**, which provides for a firm limit on total credits through this program and is a better reflection of the Board's intent than the previous version. (NEXTGEN4_SF60-13a)

> **Agency Response:** Staff appreciates the general support for the infrastructure crediting provisions. As with all rulemakings, staff agrees that public input during the workshop process for these provisions aided in the development of an effective regulatory design. Staff appreciates the specific support for the following HRI provisions: removal of credit limit based on station capital costs; adoption of a hard cap on total capacity credits.

I-1.2. *Proposed Infrastructure Crediting Provisions to Help in Achieving Goals*

Comment: Given Governor Brown's Executive Order B-48-18, which aims to have 250,000 public electric vehicle chargers installed by 2025 and five million zero emission vehicles (ZEVs) on the road by 2030[i], enhancements and amendments to the LCFS Program in this rulemaking cycle are critical to reach the State's ambitious goals.

[i] https://www.gov.ca.gov/2018/01/26/governor-brown-takes-action-to-increase-zero-emission-vehicles-fund-new-climate-investments/

(CHARGEPOINT4_SF32-1)

> **Agency Response:** Staff agrees that amendments to the LCFS program will help in achieving the goals laid out in Executive Order B-48-18.

I-2. *Not in Support for the Proposed Infrastructure Crediting Provisions*

I-2.1. Multiple Comments: *General Opposition for the Proposed Infrastructure Crediting Provisions*

Comment: We commend Staff for the success of the program to date but we are deeply concerned that Staff's proposal for DC fast charging (DCFC) and hydrogen

infrastructure crediting poses a significant threat to the integrity of the LCFS program. It is understood that the proposal to include infrastructure crediting in the LCFS program is a directive through the Governor's Executive Order B-48-18, but the inclusion of this provision should not undermine the founding principles of the LCFS. The LCFS, as a fuel neutral performance-based incentive program, has been instrumental in achieving progress towards the GHG reduction goals established in the Governor's 2030 Climate Change pillars (Executive Order B-32-15 and SB 32). If Staff intends to include infrastructure crediting into the LCFS program then it must do so in a way that promotes both fuel neutrality and actual GHG reductions of transportation fuel. (CE5_SF11-1, NRWS1_SF25-1a, NRWS2_SF58-1a)

Comment: WSPA continues to believe that infrastructure credits for hydrogen fueling stations and EV charging stations do not conform to the spirit of the LCFS program. Notwithstanding this position, WSPA does have questions and suggestions regarding the proposed program. (WSPA7_SF29-3)

Comment: LCFS staff have proposed a pathway to allow ZEV fueling infrastructure to generate LCFS credits based on its operational capacity rather than the quantity of fuel dispensed. This is a significant departure from the model the LCFS has successfully employed to date. Only DC Fast chargers and hydrogen fueling stations would be eligible for these pathways and total permit issuance through these pathways would be limited to 2.5% of the previous quarter's total LCFS deficits. We appreciate staff's willingness to engage in thoughtful, constructive discourse over the last few months. **We remain, however, opposed to the addition of capacity based infrastructure credits to the LCFS.** We feel that this breaks a well established model and that there are more appropriate policy options for supporting infrastructure investments. EV charging and hydrogen fueling station deployment is currently supported by recent CPUC proceedings, the VW settlement, CEC Grant Programs and ongoing investment of cap-and-trade revenue. While we do not believe that those sources are sufficient to meet all state ZEV infrastructure needs, they will satisfy a significant fraction of that need and adding additional revenue through a blunt, un-targeted mechanism like the proposed infrastructure capacity credits is likely to lead to inefficient, duplicative investments. (NEXTGEN4_SF60-12)

Comment: We commend Staff for the success of the program to date, but we are concerned that the recent amendments regarding "Capacity Crediting" will move the program away from what has made it successful – fuel neutrality and quantifiable carbon emissions reductions performance incentives.

…

In 2015, Scavenger, in partnership with our municipal customers became one of the first companies in America to develop an Anaerobic Digester ("AD") system to manage organic waste. This facility generates over 500 gallons of renewable natural gas ("RNG") per day that is used to fuel our compressed natural gas ("CNG") trucks. It is an incredibly clean, closed-loop system that provides a solution to meet California's

SB 1383 goals. We are proud to be one of the few “Carbon Negative” fleets in the America.

Scavenger helped pave the AD-to-RNG fueling path in California, and we did so without any sort of Capacity Crediting. We are extremely concerned that CARB staff is proposing Capacity Crediting for DC fast charging (DCFC) and hydrogen infrastructure as it threatens the integrity of the LCFS program by allowing two markets to have a material advantage over others. We believe this language should be struck, but at the very minimum, Capacity Crediting should not be limited to two industries and should promote actual GHG reductions of transportation fuel. This would still meet the Governor's Executive Order B-48-18, which we were told is the driving force behind the Capacity Crediting concept.

Staff has also concluded that excessive capital costs impede the growth of a robust network of DCFD and hydrogen stations. All fueling infrastructure, low carbon or not, requires significant capital to construct – we spent millions of dollars on our AD-to-RNG fueling project. It is not infrastructure that prohibits growth in DCFC and hydrogen markets but vehicle product technology. As previously mentioned, we explored electric trucks, and like hydrogen, they are not viable for our refuse application.

…

… however, I implore you not to deviate from the programs foundation of fuel neutrality and performance based, quantifiable carbon emissions reduction through a Capacity Crediting concept that favors certain markets over others. California needs all low carbon fuels if we are going to continue to lead the world in carbon emissions reductions.

Scavenger appreciates the opportunity to provide comments and looks forward to working collaboratively with CARB staff to maintain the integrity of the LCFS. (SCAVENGER1_SF61-1)

Comment: Please find comments from many of California's biofuels producers and associations urging the Board to maintain a fuel neutral program based on lifecycle carbon intensity, rather than adopting preferential, non-science based preferences for certain technologies.

…

We are writing on behalf of California’s biofuels producers to urge the California Air Resources Board (ARB) to maintain the LCFS program’s fuel neutrality and focus on carbon reduction. Any proposed changes to move the program away from fuel neutrality would jeopardize its success by picking technology winners and losers regardless of their actual carbon emission reductions. Together, these changes would put the program at risk of legal challenges and of meeting the carbon reductions that the state is relying on to meet its 2030 climate targets.

We are especially concerned about the proposal to give credit to hydrogen fueling stations and electric vehicle charging stations based on capacity rather than the carbon intensity and actual volume of fuel produced. This is an enormous departure in the program that moves away from the performance-based, lifecycle carbon intensity of fuels sold in California. By picking winners and losers, this proposed change contradicts the scientific underpinning of the program and makes subjective choices based on technology preferences that are not based on carbon intensity. By allowing LCFS credits to be generated for "capacity" versus actual low carbon fuel use, the LCFS program becomes ineffectual and the market will be diluted with "virtual" fuel.

Moving away from a lifecycle-based carbon intensity focus will make the LCFS program vulnerable to legal challenges that could delay program implementation. More importantly, it puts the carbon reductions -- which the state is relying on the LCFS to provide – at risk by giving credits for infrastructure rather than fuel production. LCFS will no longer rely on actual carbon reductions. This sets up a non-scientific, unreliable accounting system for one of the largest sources of carbon emissions in the state.

For all these reasons, we urge ARB to reject the proposal to provide LCFS credits for capacity rather than actual volume. In addition, we urge ARB to keep the focus of the LCFS on carbon reduction and the only scientific basis for the program, which is the lifecycle carbon intensity of participating fuels. Any other approach undermines the credibility and effectiveness of the program and reduces LCFS credit values for producers and users of actual low carbon fuel. (BFP1_SF37-1)

> **Agency Response:** Regarding fuel neutrality and the legal authority, direction, and rationale supporting ZEV infrastructure crediting, please see Response I-3.1, Departure from Fuel Neutral Approach and would not Represent Actual GHG Emission Reductions, in Chapter V. Staff does not view HRI and FCI crediting as "inefficient, duplicative investments", nor do we support the view that staff is picking "winners and losers" as suggested.
>
> The ZEV infrastructure crediting will help make up the difference between the Goals of the Governor's Executive Order and the existing funding mechanisms for ZEV infrastructure, which commenters acknowledge are insufficient to meet State goals. Because the ZEV infrastructure crediting has been reasonably designed to achieve valid program goals pursuant to state authority and policy direction, staff disagrees with the commenters' suggestion that the infrastructure provisions create legal vulnerability for the program.
>
> Staff underscores the importance of a diverse portfolio of low carbon fuels to decarbonize the many different transportation applications in this sector. Staff also disagrees that the approach for crediting ZEV infrastructure is unscientific, as the provisions are based on best available information, and the CI's of hydrogen and electricity are based on Lookup Table pathways modeled using the LCA approach detailed in the CA-GREET3.0 Lookup Table Pathways Technical Support Documentation (August 13, 2018).

Staff also contests the statement that staff established infrastructure provisions without regard for carbon emissions reductions. The HRI and FCI credit generation equations are heavily influenced by the CI of the dispensed fuel through the FSE, incentivizing reduction in CI. The infrastructure crediting provisions also do not impede on the ability of other fuels to generate LCFS credits. Please see Response I-2.2 in Chapter VI in this regard as well. The contention that staff is crediting "virtual fuel" is misplaced.

I-2.2. *Expand Capacity Crediting for All Low Carbon Fuels*

I-2.2a. Multiple Comments: *Expand Capacity Crediting for All Low Carbon Fuels*

Comment: Clean Energy remains opposed to LCFS crediting for hydrogen and DCFC fueling infrastructure unless Staff agrees to expand infrastructure crediting to all low carbon fueling infrastructure. Staff cites the Governor's Executive Order B-48-18 as the driving force behind the inclusion of DCFC and hydrogen capacity crediting proposal in the LCFS. However, the Governor also set forth a goal for a 50% reduction in petroleum use in transportation fuel by 2030 which was solidified through Executive Order B-32-15. Achieving this ambitious goal will require significant low carbon fueling infrastructure of all types, not just DCFC and hydrogen. Although the Executive Order B-48-18 specifically requires the use of LCFS to expand DCFC and hydrogen fueling infrastructure, Staff should be committed to upholding the performance standard of real GHG reductions established in the LCFS program since inception and required through a separate Executive Order. Allowing capacity crediting to all low carbon fueling infrastructure protects the integrity of the LCFS program through a fuel neutral performance standard while satisfying the both of Governor's executive orders at the same time. (CE5_SF11-2)

Comment: Napa Recycling is opposed to LCFS crediting for hydrogen and DCFC fueling infrastructure unless Staff agrees to expand infrastructure crediting to all low carbon fueling infrastructure. Staff cites the Governor's Executive Order B-48-18 as the driving force behind the inclusion of DCFC and hydrogen capacity crediting proposal in the LCFS. However, the Governor also set forth a goal for a 50% reduction in petroleum use in transportation fuel by 2030 which was solidified through Executive Order B-32-15. Achieving this ambitious goal will require significant low carbon fueling infrastructure of all types, not just DCFC and hydrogen. Although the Executive Order B-48-18 specifically requires the use of LCFS to expand DCFC and hydrogen fueling infrastructure, Staff should be committed to upholding the performance standard of real GHG reductions established in the LCFS program since inception and required through a separate Executive Order. Allowing capacity crediting to all low carbon fueling infrastructure protects the integrity of the LCFS program through a fuel neutral performance standard while satisfying the both of Governor's executive orders at the same time. (NRWS1_SF25-1b, NRWS2_SF58-1b)

Comment: The proposed amendment to allow capacity crediting for hydrogen and electric fuel infrastructure by CARB staff is problematic because it threatens the integrity of the LFCS as being fuel neutral. Instead, CARB should work to make sure that they

are equally supporting all clean fuels that are helping the state decarbonize its transportation sector. If the LCFC is going to include capacity crediting, then it should be expanded to apply to all low carbon fuels. CARB should include all forms of clean fuel to ensure the state maximizes all the benefits and availability of cleaner technology. By allowing capacity crediting for all low carbon fueling infrastructure, CARB increases options and accessibility for businesses and fleet operators to utilize all cleaner fuels. This will send a clear policy message that the Board supports all forms of clean fuel and signals that CARB is committed to creating a diverse and competitive energy market.

If California is it meet its short-term and long-term emissions reduction goals it should prioritize clean transportation fuel that is already available and contributing to emission reductions now. The importance of biofuels should not be overlooked. Renewable natural gas and other biofuels are effective pathways for the transportation sector to transition to cleaner fuel and technology.

The LCFS program has been under attack and scrutiny since its inception. Supporters of the program, like CNGVC, have been able to defend and obtain legislative support for the program because of the diverse stakeholders that are produced from its fuel neutrality. Taking that away is a step in the wrong direction and could have a dire effect on its longevity and success.

We strongly request that any change to this program not harm its fuel neutrality. We strongly believe that all “boats should float to the top” in order to get where we want to go. No one solution or fuel can solve all our problems, through working together we can continue to lead the nation in this critical time and on this critical issue.
(CNGVC4_SF28-1)

> **Agency Response:** Regarding crediting other fuels and fuel neutrality, please see Response I-3.1, Departure from Fuel Neutral Approach and would not Represent Actual GHG Emission Reductions, in Chapter V. Staff would like to clarify that Executive Order B-32-15 does not order a 50 percent reduction in petroleum consumption by 2030, but instead references the goal of achieving up to 50 percent petroleum reduction by 2030 as the grounds for an Executive Order that focuses on a different topic. Nevertheless, staff is committed to striving to achieve the Governor’s climate change mitigation goals. If the LCFS program is similarly ordered by the Governor to incentivize fueling infrastructure for non-ZEV fuels, staff will provide a regulatory proposal accordingly.
>
> Staff disagrees with the commenter’s suggestion that the capacity crediting provisions reduce the diversity of the LCFS. Capacity credits are limited to a maximum of five percent of program deficits, thereby leaving 95 percent of needed credit generation to the diverse set of credit opportunities that the LCFS has traditionally supported. Moreover, staff took several steps to simplify participation in the program for producers of biofuels by creating Simplified CI Calculators for Tier 1 feedstock-fuel combinations. Notably, staff created four Simplified CI Calculators for Tier 1 biomethane pathways, a step which is expected to reduce compliance burden for applicants and which demonstrates

that staff continues to make program improvements to support biofuel participation in the program.

I-2.2b. Multiple Comments: *Capital Risk for Station Owners*

Comment: Staff has concluded that excessive capital costs have impeded the growth of a robust network of DCFC and hydrogen fueling stations, therefore capacity crediting is necessary to mitigate such costs. Capital risk is not unique to DCFC and hydrogen fueling infrastructure. All fueling infrastructure, low carbon or not, requires significant capital to construct and operate. Clean Energy, for example, has invested hundreds of millions of dollars to build and maintain a robust network of NGV fueling stations in California. Fleet owners have expended significant capital for both fueling infrastructure and low carbon fuel vehicles. Most importantly, waste haulers and municipalities have started investing in organics diversion projects in accordance with SB 1383. These projects carry significant capital risk to which there is zero regulatory relief akin to the proposed DCFC and hydrogen capacity crediting provision. Regardless of end use, these capital investments carry significant risk but also all contribute towards the State's goal which is to reduce GHG emissions from the transportation sector. Regulatory policy should not dictate winners and losers among fuels in the LCFS program.

Allowing capacity crediting for all low carbon fueling infrastructure reduces upfront capital risk for station owners and will significantly advance low carbon fueling options in California. This is especially true for biofuels such as biomethane that can achieve a "carbon negative'" well to wheels GHG reduction when consumed as a vehicle fuel through an NGV fueling station. Furthermore, allowing capacity crediting for all low carbon fuels maintains the LCFS founding principle of fuel neutrality underscoring the need for a diversified portfolio of all low carbon fuels in order to meet California's GHG reduction goals. (CE5_SF11-3)

Comment: Staff has concluded that excessive capital costs have impeded the growth of a robust network of DCFC and hydrogen fueling stations, therefore capacity crediting is necessary to mitigate such costs. Capital risk is not unique to DCFC and hydrogen fueling infrastructure. All fueling infrastructure, low carbon or not, requires significant capital to construct and operate. Waste haulers and municipalities have started investing in organics diversion projects in accordance with SB 1383. Napa Recycling is currently replacing our entire fleet of 40+ trucks with state-of-the art CNG vehicles. We also have been awarded a CEC grant to help fund an anaerobic digestion project that will create biomethane from organics that can fuel our fleet with carbon negative bioCNG. These projects carry significant capital risk to which there is zero regulatory relief akin to the proposed DCFC and hydrogen capacity crediting provision. Regardless of end use, these capital investments carry significant risk but also all contribute towards the State's goal which is to reduce GHG emissions from the transportation sector. Regulatory policy should not dictate winners and losers among fuels in the LCFS program.

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California. This is especially true for biofuels such as biomethane that can achieve a "carbon negative" well to wheels GHG reduction when consumed as a vehicle fuel through an NGV fueling station. Furthermore, allowing capacity crediting for all low carbon fuels maintains the LCFS founding principle of fuel neutrality underscoring the need for a diversified portfolio of all low carbon fuels in order to meet California's GHG reduction goals. (NRWS1_SF25-2, NRWS2_SF58-2)

> **Agency Response:** Regarding crediting other fuels, please see Response I-3.1, Departure from Fuel Neutral Approach and would not Represent Actual GHG Emission Reductions, in Chapter V. Staff acknowledges that renewable natural gas pathways can constitute significant CI reductions, and in some cases be certified as carbon negative, and staff encourages further production of such fuels. Staff believes that the current potential revenue to be gained through LCFS credits and Renewable Fuel Standard RINs is more than sufficient to incentivize production of renewable natural gas. Without crediting renewable natural gas infrastructure, staff estimates that all natural gas used for transportation applications in California will be renewable by the early 2020s (see Illustrative Compliance Scenario Calculator, published on August 15, 2018).

I-2.3. Multiple Comments: *Establish a Credit Advancement Program*

Comment: The LCFS was built as a performance incentive program based on real quantifiable reductions in carbon emissions from the California transportation fuel sector. According to the 2009 Initial Statement of Reasons:

"The LCFS framework is based on the premise that each fuel has a "lifecycle" GHG emission value that is then compared to a standard. This lifecycle analysis represents the GHG emissions associated with the production, transportation, ***and use of low carbon fuels in motor vehicles."***

The foundation of the LCFS program has always been based around a lifecycle emissions standard for fuel {not infrastructure} which promotes two key elements of the LCFS program:

- Real quantifiable GHG reductions of California transportation fuel;
- Fuel Neutrality.

Staff needs to maintain these key principles through the implementation of a capacity crediting provision. Capacity crediting should serve as a risk mitigating factor for upfront capital costs for a station owner and not a supplemental credit generating provision that does not represent real reductions in GHG emissions. Capacity crediting needs to be viewed as a "credit advancement program" meaning that a fueling station may not generate credits beyond actual GHG reductions achieved through fuel sales. Essentially, station owners are borrowing against future credit generation (through actual fuel sales) to fund initial start-up capital costs. As fuel deliveries increase, actual fuel credits will surpass capacity credits generated at which point the station owner can generate fuel credits per the normal LCFS operation. This ensures that all credits

issued in the LCFS represent an actual metric ton of GHG emission reduction as the program was intended to do. This will prevent a buildup of "phantom" credits that are not tied to actual fuel consumption. Furthermore, this promotes the fuel neutral performance standard of the LCFS because all credits must be tied to actual fuel consumption. (CE5_SF11-4, NRWS1_SF25-3, NRWS2_SF58-3)

> **Agency Response:** Staff did not implement the suggestion by the commenters to create a "credit advancement program," in which credits are essentially borrowed from future credits generated by reporting fuel transactions. While the commenters' suggestion would provide up-front capital that would aid in the initial establishment of a hydrogen station/DC fast charger, staff has observed that the operational costs of ZEV infrastructure and in particular hydrogen stations also remain significant at this time, due to the nascent status of the technology. The commenters' suggestion would not provide the level of operational support necessary to maintain stations and avoid the risk of stations being built and then abandoned prior to the buildup of vehicles and demand for the stations. With regards to fuel neutrality and credits potentially not representing present GHG emissions reductions, please see Response I-3.1, Departure from Fuel Neutral Approach and would not Represent Actual GHG Emission Reductions, in Chapter V.

I-2.4. Multiple Comments: *Removal of Cap on HRI Credit Revenue per Station*

Comment: With respect to the hydrogen refueling infrastructure (HRI) provisions, we were surprised and disappointed that the proposal includes no cap on the total HRI credits available for a single station. The cap discussed at the August 8th workshop seemed like a straight-forward means to ensure that LCFS HRI credits do not provide a windfall to HRI developers far in excess of what is required to make HRI economically viable. Since the total number of HRI credits in the program is capped, offering too much to any one station reduces the number of stations that can be supported under the cap. (UCS4_SF26-4)

Comment: Proposed § 95486.2(a) and § 95486.2(b) contain regulatory language for hydrogen refueling infrastructure (HRI) credits and DC fast charging infrastructure (FCI) credits, respectively. At the August 8, 2018 CARB workshop, CARB staff indicated that the value of both HRI and FCI credits would be limited such that the sum of grant funding and the HRI/FCI credit value could not exceed the total installation cost of the station. However, only § 95486.2(b) related to FCI credits contains the relevant regulatory language in § 95486.2(b)(4)(H). WSPA requests that CARB clarify the apparent disparity between the proposed regulatory language and the workshop presentation. (WSPA7_SF29-4)

Comment: PG&E also notes that the regulation limits the infrastructure credits generated by DC fast chargers to the capital cost of the station, but does not apply the same limit to H2 stations. PG&E believes that both zero-emission fuels should be treated consistently and recommends that the same rules be applied to both infrastructure crediting programs. (PGE3_SF49-8)

Comment: The current proposal provides LCFS credits to hydrogen and DC fast charging station developers based on the capacity of the stations they install, regardless of fuel volumes dispensed. At the August 8 workshop, staff proposed capping the total amount of infrastructure credits going to each DC fast charger or hydrogen station at the total capital cost of the unit, with a 10% discount rate on future credits to reflect ongoing costs. However, the second 15-day package removes the cap on hydrogen but leaves it in place for DC fast charging. As currently proposed, hydrogen station developers could receive LCFS capacity credits substantially in excess of the all-in cost of the station.

This proposed change undercuts a central tenet of the LCFS, which is fuel and technology neutrality, and is a departure from its successful model of basing incentives on real-world emission performance.

We recognize CARB's desire to support ZEV infrastructure in order to help achieve California's critical climate and air quality goals. This provision, however, stretches a market-based program too far: it guarantees that hydrogen project developers will recover the full capital cost of infrastructure in addition to assuring a high rate of return, a benefit offered to no other fuel pathway. Credits issued through this provision will reduce the support being offered to fuels that have demonstrated their ability to reduce near-term emissions. The current provision also guarantees capacity revenue for stations that have already been built. Capping the support to each station at its total capital cost, as proposed at the August 8 workshop, puts a sensible limit on the scope of this plan while still offering a significant increase in total assistance to ZEV infrastructure. (ORGS1_SF54-2)

Comment: Finally, CalETC notes that the second round 15-day modifications do not have equal cost limits for DC fast charging stations and hydrogen fueling stations (e.g., different sunset provisions). In a future rulemaking, CalETC urges CARB to apply the same rules to DC fast charging and hydrogen fueling stations. (CALETC4_SF50-6)

> **Agency Response:** Staff acknowledges that the presentation at the August 8, 2018 workshop included a provision that limited HRI credit revenue generation per station to the capital costs of the station, and that this provision was subsequently removed prior to the public posting. The cap on total revenue was removed in order to provide a sufficient level of support to hydrogen stations to both incentivize development and provide operational support until hydrogen supply costs decline (through scale and vehicle adoption) and associated hydrogen demand increase to sustainable levels. Although attaining the Governor's goal of 10,000 DC Fast Chargers by 2025 requires regulatory support, staff believes that maintaining a cap on total FCI credit revenue per FSE was reasonable, given the higher penetration of EVs to date and the established infrastructure for electricity supply. However, in place of a cap on HRI credit revenue, a provision was included requiring HRI applications to justify the location and capacity of each station with regards to the expected contribution to the existing hydrogen refueling network in California. This requirement will prevent inappropriate station siting and capacity buildout which could otherwise

result in over-crediting of stations and a reduction in total stations supported by the HRI provisions. In addition, staff contests the statement that hydrogen stations are guaranteed to recover the full capital cost of infrastructure and are assured to receive a high rate of return. There are several scenarios in which hydrogen stations receiving HRI credits may not even break even, depending on many factors, including the availability of CEC grants, the cost of delivered hydrogen, LCFS credit prices, and more. Regarding fuel neutrality, please see Response I-3.1, Departure from Fuel Neutral Approach and would not Represent Actual GHG Emission Reductions, in Chapter V. Regarding ongoing performance review, please see Response to I-6 in this chapter.

I-2.5. Multiple Comments: *Reduction in GHG Emissions Benefits and Excessive Revenue as a Result of Infrastructure Crediting Provisions*

Comment: *Capacity Credits for Electric/Fuel Cell Infrastructure.* In addition, Growth Energy continues to have concerns regarding the proposal to provide capacity credits for electric and fuel cell vehicle infrastructure. As demonstrated in Exhibit "B," the alleged GHG benefits of the LCFS regulation would decrease significantly if the Proposed Modifications are adopted. Specifically, assuming the LCFS does not result in fuel shuffling, "the annual amount of GHG reductions that would not be realized by the LCFS program due to the proposed infrastructure crediting provisions would range from about 0.8 to 1.6 $MMTCO_2eq$ per year and the cumulative loss in GHG emissions from 2019 to 2030 could amount to 14.0 $MMTCO_2eq$." (Exhibit "B" at 1.) This result is inconsistent with AB 32 and SB 32. (See Health & Saf. Code, §§ 38560.5, subd. (c); 38562, subd. (a); 38566.)

The Proposed Modifications would also result in a substantial amount of windfall revenue to operators and owners of DC fast charge and hydrogen stations which could total $150 to $300 million per year. (Exhibit "B" at 1.) These benefits will in turn reduce the incentives for alternative fuel providers to sell low CI fuel in the aggregate amount of $150 to $300 million per year, contrary to the purpose and intent of the LCFS program. (GROWTHENERGY3_SF31-3)

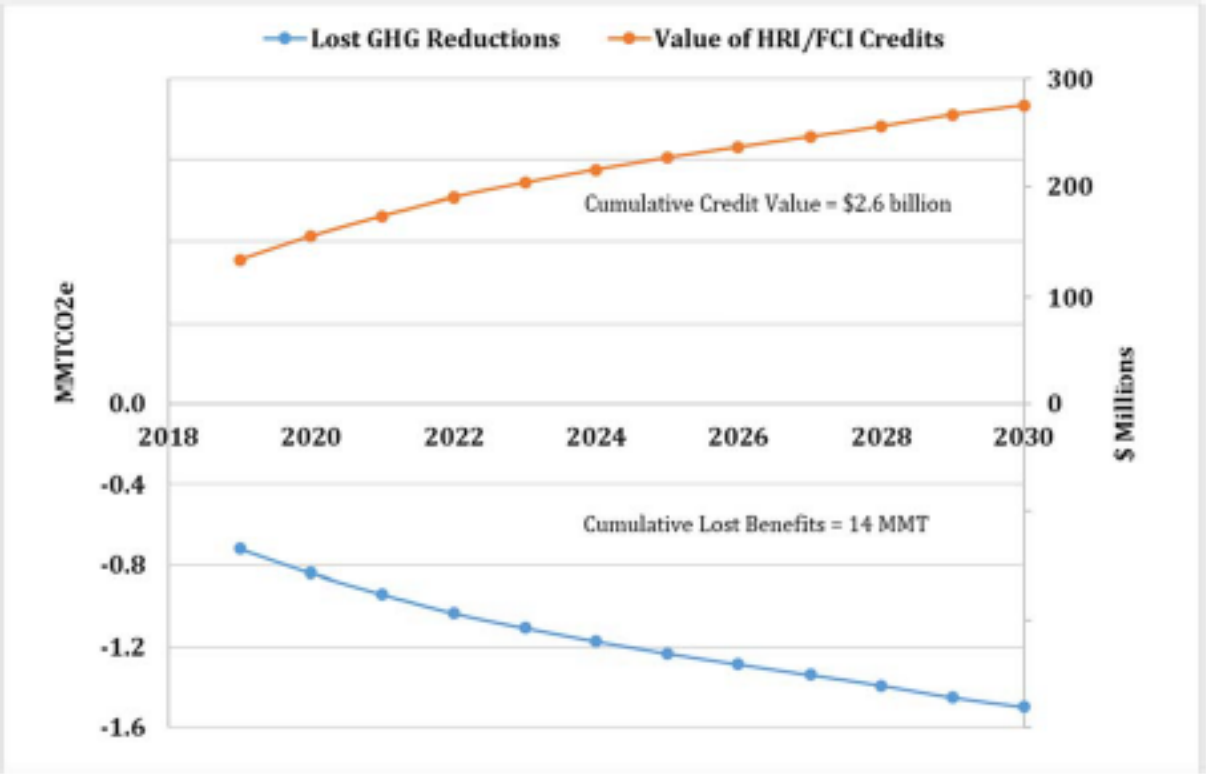
Comment: CARB's Proposal to Provide "Capacity" Credits for Electric and Fuel Cell Vehicle Infrastructure is Contrary to the Purpose of the LCFS and Should Not Be Included

As part of the second 15-day notice, CARB has made a number of modifications to the proposed new section of the low carbon fuel standard regulation ("LCFS"), 95486.2 to Title 17, California Code of Regulations, which is intended to provide LCFS credits to hydrogen stations and direct current (DC) fast charging stations based on the installed capacity to deliver hydrogen and electricity in addition to the LCFS credits provided for the "fuel" that is actually delivered to and used by electric (EV) and fuel-cell (FCV) vehicles. However, none of these proposed changes address the fundamental issues raised by the public and Growth Energy during comments on the first 15-day notice. Rather, Section 95486.2 continues to contemplate that LCFS credits would be provided to owners and operators of DC fast charging and hydrogen stations for not actually

selling low-CI fuel, but for the theoretical sales they could have if their stations were utilized to their full capacity. The direct result of this process is a loss in the GHG reductions that would result from the proposed LCFS, and windfall revenue for the station operators.

In order to put the potential magnitude of these issues into perspective, Figure 1 shows the estimated maximum amount of GHG reductions that could be lost due to the implementation of Section 95486.2 and the estimated maximum amount of windfall revenue that owners and operators of DC fast charging and hydrogen stations could realize based on the deficit values projected in the August 15, 2018 version of the Illustrative Compliance Scenario Calculator posted on CARB's website[1] as configured for the "Low Demand" and "Project/LD/Low ZEV/20%/infra" cases. The data in the figure assume that 5% of total deficits each year from 2019 to 2030 are provided as infrastructure credits and that the value of each LCFS credit received is $184 – the average LCFS credit price for Q2, 2018. As shown, the annual amount of GHG reductions that would not be realized by the LCFS program due to the proposed infrastructure crediting provisions would range from about 0.8 to 1.6 $MMTCO_2eq$ per year and the cumulative loss in GHG emissions from 2019 to 2030 could amount to 14.0 $MMTCO_2eq$. Similarly, windfall revenue received by operators and owners of DC fast charge and hydrogen stations could amount to about $150 to $300 million per year with the potential cumulative value being about $2.6 billion. Under CARB's high fuel demand scenarios, lost GHG benefits and windfall revenues would be even greater. It should also be noted that CARB staff acknowledges in Attachment G to the 2nd 15 day notice that accounting for infrastructure credits for hydrogen and DC fast charges is one of the factors that lead to a reduction in the cumulative GHG benefits claimed for the LCFS program from 117 to 97 $MMTCO_2eq$ (a loss of 17%) compared to the current conditions baseline and from 70 to 63 $MMTCO_2eq$ (a loss of 10%) compared to the business-as-usual scenario.

Figure 1. Potential Loss in GHG Reductions and Windfall Revenue Transferred Under CARB's Proposed Infrastructure "Capacity" Program



(GROWTHENERGY3_SF31-14a)

Agency Response: While staff acknowledges that the infrastructure crediting provisions may result in entities generating significant credit revenue, staff takes issue with several factors in Growth Energy's and NextGen's calculation of total revenue under these provisions. The assumption that credit value will remain at $184 per metric ton is inconsistent with staff's scenario modelling. In addition, the analysis assumes that capacity credits are generated at the maximum allowable rate starting in 2019 and running through 2030. This assumption is not reasonable given the time it takes to develop and build stations and the cutoff date for applications at the end of 2025. Staff's own analysis presented in the Illustrative Compliance Scenario Calculator, shows infrastructure provisions generating less than 10 million cumulative credits and less than $1 billion in cumulative revenue over the time period of 2019 through 2030.

Staff acknowledges that infrastructure crediting may result in a reduction in GHG emissions reductions in the short term. However, the Governor's direction through Executive Order B-48-18 clearly demonstrate that the LCFS is to leverage mechanisms within the program, which has been interpreted as credit generation, to aid in the buildout of zero-emission infrastructure to remove a key barrier for commercial expansion of zero-emission vehicles in the near future.

Staff is confident that the HRI and FCI provisions as written will play a key role in expanding ZEV penetration in California, while the LCFS as a whole simultaneously continues to incentivize GHG emissions reductions through all low carbon fuels. Please see Response D-6.11i in this chapter with regards to modeling submitted by that stakeholder. Regarding ongoing review of the program, please see Response I-6, Ongoing Review of Performance of Infrastructure Credit Provisions, in this chapter.

I-2.6. *Alternative to the Proposed Capacity Credits*

Comment: CARB Has a Viable Alternative to the Proposal to Provide "Capacity" Credits for Electric and Fuel Cell Vehicle Infrastructure that would Achieve the Same Result without Sacrificing GHG Reduction Benefits of the LCFS Program

As part of the second 15-day notice CARB is proposing changes to Title 17, CCR, section 95483(c)(1)(A), which would "*require an opt-in electrical distribution utility (EDU) or its designee, generating base credits for residential EV charging to participate in a statewide point of purchase rebate program funded exclusively by LCFS credit proceeds, if such a program is established.*"

The proposed required contribution of all LCFS credits generated from residential EV charging vary depending on the type of EDU. This is shown in Table 1 below, which is taken from the draft regulatory text published as part of the Second 15-day notice. Table 1 shows the required contribution for all electrical distribution utility (EDU) types to the point of purchase rebate program is substantially less than 100%.

Table 1. Proposed EDU Contributions of LCFS Credit Proceeds to a Statewide Point of Purchase Rebate Program

EDU category	% Contribution in years 2019 through 2022	% Contribution in years 2023 and subsequent years
Investor-owned Utilities	67%	67%
Large Publicly-owned Utilities	35%	45%
Medium Publicly-owned Utilities	20%	25%
Small Publicly-owned Utilities	0%	2%

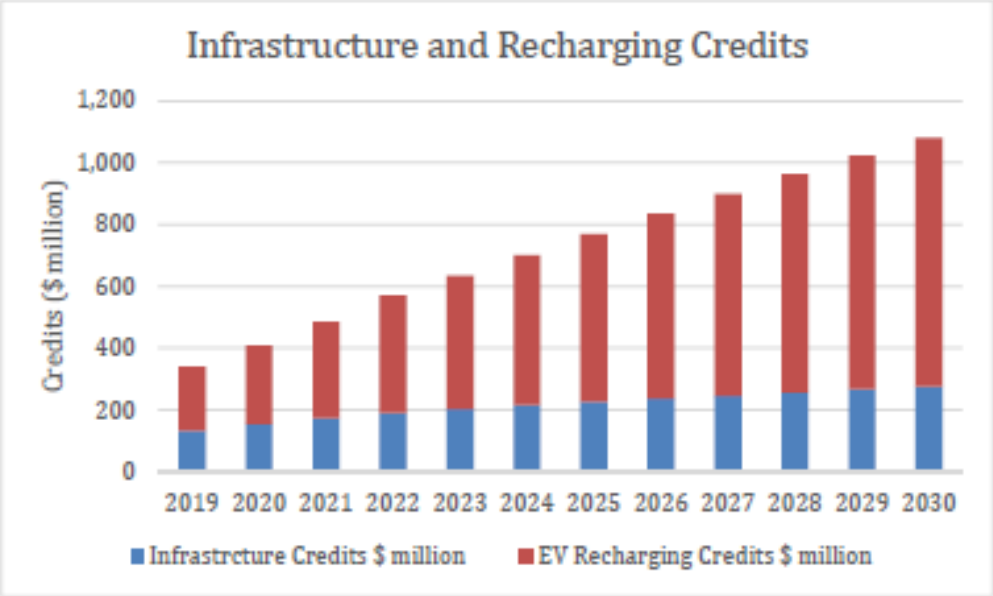
In addition, CARB is proposing changes to Title 17, CCR, section 95491(d)(3)(A)2 that concern unmetered residential EV recharging and are intended to *"clarify that an LSE generating credits must use all credit proceeds to benefit the current or future EV drivers across California and not just within its service territory. This would allow opt-in utilities to use base credits proceeds for a statewide point of purchase rebate."*

As has been indicated in previous comments, the LCFS credits generated from unmetered residential charging are at best estimates. These credits are not based on actual fuel delivery, as is required for all other fuels under the LCFS. As a result, residential metering or verification of fuel use by other means should be required. While LCFS credits from EV recharging at least have some basis in terms of actual GHG reductions, the LCFS credits CARB is proposing to give to underutilized DC fast charging and hydrogen stations do not result in any such reductions.

As shown above, not all of the value of LCFS credits associated with EV charging are being required to be provided for use in the statewide point of purchase rebate program. Thus, the value of the remaining LCFS credits is based, at least to some degree, on actual reductions in GHG emissions. As such, even if CARB has been directed to provide "capacity" credits for hydrogen and DC fast charging stations "to support the expansions of such infrastructure as directed by Governor's Executive Order B-48-18", as stated on pages 6 and 7 of Appendix F to the first 15-day notice, CARB could use the remaining value of the residential EV charging credits to provide funding for underutilized DC fast charging and hydrogen stations rather than creating fictitious LCFS credits that are not based on actual GHG reductions.

It appears that there should be ample funding available for EV/FCV infrastructure. Figure 2 compares the maximum values of the LCFS credits proposed by CARB staff for infrastructure, to the total value of credits from recharging of light-duty EVs as documented in the August 15, 2018 version of the Illustrative Compliance Scenario Calculator for the "Low Demand" and "Project/LD/Low ZEV/20%/infra" cases. As shown in Figure 2, the magnitude of the value of the infrastructure credits proposed by CARB is small compared to the value of the credits that EDUs receive from residential EV recharging. Although availability of DC fast charging to the extent that such capacity is actually needed could "*benefit the current or future EV drivers across California,"* CARB would simply have to change EV to "Zero Emission Vehicle (ZEV)" to allow for the use of funds from EV recharging to also support hydrogen station infrastructure, which could obviously benefit current or future FCV drivers across California.

Figure 2. Comparison of Revenue Associated with CARB Proposed Infrastructure Credits with Available Revenue from Recharging of Light-Duty EVs.



Based on the above, CARB should abandon its proposal to create LCFS credits that are not based on actual GHG emission reductions to support DC fast charging and hydrogen stations. Instead, CARB should simply require that the surplus credit value generated by the EDUs beyond those needed for the point of purchase rebate program be used to provide funding for underutilized DC fast charging and hydrogen stations. In addition, CARB should use these surplus funds to promote the development of infrastructure for other low-CI fuels such as E85, as use of E85 in California is dramatically limited by the lack of a widespread distribution and dispensing infrastructure. (GROWTHENERGY3_SF31-15)

Agency Response: As the commenter noted, under section 95491(d)(3)(A) utilities are required to use all credit proceeds to benefit the current or future EV drivers in California. In response to Board Resolution 18-17, staff proposed changes to facilitate a statewide point-of-purchase rebate program funded by LCFS base credit proceeds. Staff believes utilities have an important role to play in promoting EV adoption beyond just offering point of sale rebates. In fact, utilities are already implementing programs (or are planning future programs) focused on EV adoption in disadvantaged communities, including multi-family residential EV charger rebates, used EV rebates, education and outreach programs, EV charging- specific electricity rates, and more. Therefore, staff proposed that opt-in utilities must contribute a minimum percentage of base credits, or the base credit proceed, for the statewide rebate program, allowing the remaining share to continue to be used for funding other programs that promote the use of electricity as a low carbon transportation fuel.

Staff did not accept the commenter's recommendation to use the remaining residential charging credits for the ZEV infrastructure provisions, choosing instead to let the utilities retain discretion in how those funds are spent. Further, a utility may choose to contribute greater than the minimum percentage of their base credit proceeds to the statewide rebate program (even up to 100 percent).

Regarding crediting other fuels, please see Response I-3.1, Departure from Fuel Neutral Approach and would not Represent Actual GHG Emission Reductions, in Chapter V.

Lastly, staff did not think it reasonable to require metering of household EV charging for verification of residential charging credits. It is unreasonable to expect that households should be required to install utility-grade sub-meters on site for the purposes of generating credits for utilities, when such equipment is unnecessary for most residential charging needs. The LCFS credit calculation for residential charging based on a limited subset of metered residential charging is robust as designed.

I-3. *Comments on HYSCAPE Model*

I-3.1. Multiple Comments: *Support for HYSCAPE Model*

Comment: We agree that an accurate, robust model is needed so that CARB can evaluate station grant proposals and determine station capacity, and that the proposed HyC model can meet these needs.

Recognizing the urgency to provide feedback to CEC and CARB regarding the tool's performance, we have installed and used the tool to model performance of our Anaheim station and provide the following feedback regarding its effectiveness:

1. We believe the tool is sufficiently robust, providing a systematic, predictable and transparent method that scores proposed equipment relative to an ideal case. **As such, HyC should be suitable to meet the anticipated needs of CARB and industry.**
2. During our testing of the tool from 7/24/2018 to 8/14/2018, we identified several areas of improvement related to parameter inputs, operational limits, and inconsistencies. These findings were detailed in a previous communication with CEC and **we believe that all of our concerns have been addressed in the most recent version of the tool.**
3. While we have not had sufficient time to perform a comprehensive evaluation of the tool with all of our designs, we are confident that the tool is ready for implementation. **We encourage CARB to establish a regular review process by which updates to the model can be evaluated and considered for future implementation. (**AL2_SF1-2)

Comment: Hydrogen Station Capacity Evaluation Tool: We agree that an accurate, robust model is needed so that CARB can evaluate station grant proposals and

determine station capacity, and that the proposed HyScape model can meet these needs. Recognizing the urgency to provide feedback to CEC and CARB regarding the tool's performance, we have installed and used the tool to model performance of our stations and provide the following feedback regarding its effectiveness:

- We believe the tool is sufficiently robust, providing a systematic, predictable and transparent method that scores proposed equipment relative to an ideal case. As such, HyScape should be suitable to meet the anticipated needs of CARB and industry.
- During our testing of the tool from 7/24/2018 to 8/14/2018, we identified several areas of improvement related to parameter inputs, operational limits, and inconsistencies. These findings were detailed in a previous communication with CEC and we believe that all of our concerns have been addressed in the most recent version of the tool.
- While we have not had sufficient time to perform a comprehensive evaluation of the tool with all of our designs, we are confident that the tool is ready for implementation. We encourage CARB to establish a regular review process by which updates to the model can be evaluated and considered for future implementation. (H2IND3_SF6-2, H2IND4_SF7-2)

Agency Response: Staff appreciates the feedback that the HYSCAPE model should be suitable for its intended use and that the commenter's concerns have been addressed. Staff encourages stakeholders to inform staff about any concerns with the model during implementation of the updated program, for consideration in a future rulemaking, at which time a new version of the model may be incorporated by reference.

I-4. *Requirements to Generate HRI Credits*

I-4.1. *Application Requirements and Requirements to Generate HRI Credits*

I-4.1a. Comment: OEM station approval: we recommend modifying the requirement that "[a]t least three OEMs have confirmed that the station meets protocol expectations, and their customer can fuel at the station" (Sec. 95486.2(a)(4)(D)) to require that the station owner has confirmed that the fueling interface conforms to SAE International J2601: 2016, Fueling Protocols for Light Duty Gaseous Hydrogen Surface Vehicles (www.sae.org), or the most recent version of the standard published and promulgated by the SAE, and has been tested per CSA HGV 4.3: 2012, Test Methods for Hydrogen Fueling Parameter Evaluation and related devices, or the most recent published version of the standard, and confirmed by either (1) a 3rd party Nationally Recognized Test Lab (NRTL) as approved by CARB, or (2) the U.S. Department of Energy Hydrogen Station Equipment Performance (HyStEP) device as practicable, or an equivalent process for fueling interface confirmation. (H2IND3_SF6-3, H2IND4_SF7-3)

Agency Response: Please see Response I-9.1 in Chapter V.

I-4.1b. Comment: Deadline to Open: as drafted, the regulation requires that "a station must be operational within 24 months of application approval." (Sec. 95486.2(a)(4)(F).) We believe this deadline is an appropriate requirement to develop approved stations, but suggest that it should not result in a forfeiture of HRI credits when delays are caused by permitting agencies and not by the applicant. Permitting delays that exceed 30 days should be excluded from the 24-month period. (H2IND3_SF6-5, H2IND4_SF7-5)

> **Agency Response:** Please see Response I-9.2 in Chapter V.

I-4.1c. Comment: § 95486.2(a)(2)(J) requires that an HRI application include arguments justifying the construction of the station based on elements such as contributing to "robust growth of the statewide hydrogen fueling network." This is not part of the HRI Pathway Eligibility criteria listed in § 95486.2(a)(1) and suggests that staff may apply additional subjective criteria in approving or rejecting applications. WSPA requests that these application requirements either be removed or made an objective and measurable part of the eligibility criteria. (WSPA7_SF29-5)

> **Agency Response:** Staff disagrees that the application requirement to submit a justification of hydrogen station location and capacity must be included in the eligibility criteria to apply for HRI applications. Section 95486.2(a)(1) merely establishes the bare minimum requirements necessary in order to qualify to submit an application for HRI crediting, whereas Section 95486.2(a)(2), HRI Application Requirements, lists the specific documentation that staff will use in determining whether or not to approve an application. Subsection 95486.2(a)(2)(J) simply provides the Executive Officer with a degree of flexibility to review the appropriateness of applications and guards against over-crediting of stations due to poor siting or over-building, which the commenter lists as a concern in WSPA7_SF29-4.

I-4.2. *Proposed Capacity Credit Pathways Award an Excessive Amount of Credits to Participating Stations*

Comment: *The Proposed Capacity Credit Pathways Award an Excessive Amount of Credits to Participating Stations, Especially in the Case of HRI*

The proposed HRI and FCI pathways, as described in § 95486.2 are intended to support the deployment of fueling infrastructure in advance of anticipated ZEV demand, in support of Executive Order B-48-18. We appreciate staff's effort to design a system which rewards aggressive deployment of refueling and fast charging infrastructure, which will help improve the market's adoption of ZEVs. Unfortunately, the current proposal still goes too far, especially in the case of HRI.

Every dollar which supports possible future reductions through investment in infrastructure would otherwise have supported real, and more timely reductions through purchases of credits resulting from sales of low-carbon fuel under normal LCFS pathways. While we agree with the State's desire to support ZEV infrastructure, there

has been an insufficient discussion of what level of support is appropriate to achieve the desired goal. The current program exceeds what current research and modeling indicates is necessary to support the deployment of a robust ZEV fueling infrastructure network. In the case of HRI, it could exceed that level by millions of dollars per station.[5] That exceedance directly trades off against real emissions reductions from other LCFS credit pathways.

[5] See out attached credit model.

The FCI provisions in § 95486.2 (b) include a cap on per-station capacity credits, a limited interpretation of maximum station capacity, as well as a more reasonable period under which credits could be issued. While we feel like the FCI provision is very likely to err on the side of over-compensating station developers, these sensible protections limit the potential risk and ensure that by 2030, these stations will have transitioned to normal LCFS credit generation pathways.

The HRI provisions in § 95486.2 (a), however, create a multi-decade commitment that could give project operators revenue from state-backed carbon instruments substantially in excess of total capital and operational costs. This excessive level of support will create a troubling precedent for future infrastructure deployment programs, it mutes incentives for private companies to reduce capital costs and the carbon intensity of their fuels, and it commits California fuel consumers to paying tens of millions of dollars per year for hydrogen stations through the next 20 years.

We strongly feel that the proposed per-station cap on total HRI credits, which was discussed at the August 8 workshop, would provide a sufficient addition to existing state infrastructure incentives to support the deployment of hydrogen capacity which meets the targets set out by Executive Order B-48-18. **We oppose the adoption of the HRI pathways in the current proposal, which lack such a limit,** especially given that the available evidence indicates that such a cap would still result in stations recovering their capital costs in a reasonable time period. We understand, however, that further amendments to address this issue would risk delaying the re-adoption of the LCFS as a whole. If an immediate solution to this problem is impracticable, then we call on CARB to instruct staff to address this problem at the earliest opportunity.

We strongly urge the Board to instruct staff to review the performance of the infrastructure capacity credit provisions as part of the next LCFS rulemaking. This review should consider the evidence from early HRI and FCI applications, consultation with stakeholders and independent experts, and all relevant published research to determine whether the HRI pathways offer an appropriate and efficient level of support to achieve the goals of Executive Order B-48-18, SB 32, and other applicable State energy and emissions targets. If this review concludes that these pathways do not provide an appropriate and efficient level of support, staff should suggest amendments to address any issues identified by the review.

Rationale for the suggested action:

As written, the HRI and FCI pathways would likely yield far more revenue from the sale of HRI and FCI credits than is necessary to shield project developers from financial risk arising from building fueling infrastructure in advance of vehicle deployment. We submitted a HRI and FCI cost and revenue model as part of our June comment letter. We have had several conversations with staff and stakeholders in the hydrogen fueling station business since that time and requested review and comment. We have noted reviewed comments on this rulemaking as well as other publicly available sources and have found no publicly-available evidence that our model makes any significant methodological errors. We had numerous constructive conversations with staff regarding the model development and appreciate their engagement on this subject. We are submitting an updated version of our cost model with this comment, which includes cost of capital and operational costs based on the most recent NREL hydrogen infrastructure modeling, which CEC uses as their main source of evidence when developing their hydrogen infrastructure planning documents. We reviewed the public comment record and could not find any alternative values for capital or operational cost submitted by stakeholders.

The submitted HRI model evaluates capital and operational costs for stations within the proposed program on both a per-station and aggregate bases and considers a high and low growth scenario for hydrogen transportation fuel.[6] The "Hydrogen Capacity Effect" tab evaluates aggregate HRI credit generation for hydrogen stations through 2025 on a growth trajectory consistent with attaining the 200 station target established by Executive Order B-48-18.,The "Hydrogen Station Revenue" tab provides an estimate of cash flow on a per station basis under the same conditions. The aggregate HRI modeling considers the existing fleet of hydrogen fueling stations which are operational, permitted or under construction,[7] then simulates the deployment of a sufficient number of stations on an approximately linear trajectory to yield approximately 200 stations by the end of 2025. It is worth noting that the proposed HRI provisions will direct around $50 million in LCFS credit[8] to these existing stations, even assuming they reach their maximum average utilization, as recommended by NREL and CEC, by 2030.[9] We feel that providing revenue to stations which are already operational and dispensing their intended level of fuel at commercial rates is an inefficient approach to incentivizing new stations.

[6] See attached Excel File Capacity_Credit_Estimates_v1.0

[7] 64 stations are identified by CEC data, however the construction of one has been indefinitely delayed and two others were in early conceptualization stages. These three were excluded, yielding 61 stations with an average capacity of 263 kg/day of hydrogen. Source: CEC Joint Agency Staff Report: Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California, CEC Report number 600-2017-002 and California Fuel Cell Partnership SOSS system.

[8] All revenue estimates in this comment assume constant $150 LCFS credit prices, unless otherwise noted. Both CARB's Illustrative Compliance Scenario calculator and recent research by Cerulogy indicate a flat or slightly tightening LCFS credit market through 2025, which implies this is a conservative estimate.

[9] It is recommended that stations be built such that typical utilization does not exceed 75% of nameplate capacity, in order to ensure that stations maintain surge capacity. Since HRI credits are based on nameplate capacity, this means stations will continue to receive HRI credits even if future sales volumes meet their design expectations.

When new and existing stations are considered together, the high-growth hydrogen scenario[10] estimates that approximately $260 million in HRI credits will be disbursed from 2020-2025, after which most stations will have at least 10 more years of eligibility for continued support through this program. Under the lower-growth scenario,[11] HRI funding exceeds $400 million through 2025.

[10] Based on CEC state-wide hydrogen consumption forecasts.

[11] Based on hydrogen growth in the 20% target, high-demand, high-ZEV scenario in the CARB Illustrative LCFS Compliance Scenario calculator.

CEC estimates that $125 million in funding beyond existing state commitments is required to deploy 100 hydrogen stations by 2024.[12] Even assuming no economies of scale apply to stations beyond the initial hundred, the HRI provision projects to at least meet this need and possibly exceed it by as much as 50% through the first six years of the program. The program will continue to provide support through the late 2030's, far exceeding the level of support required as indicated CEC research.

[12] http://www.energy.ca.gov/2017publications/CEC-600-2017-002/CEC-600-2017-002.pdf

On a per-station basis, the proposed HRI provisions will yield $3.1 to $4.4 million in revenue per station through the first six years of eligibility. Based on feedback from staff and stakeholders, the model submitted in July was updated to include capital costs, station operational and maintenance expenses, hydrogen procurement costs and interest on station capital. Even when these costs are considered, stations fully repay their capital cost under the high-growth scenario by year 7 and the low-growth scenario by year 9. In both scenarios, the stations are more than meeting ongoing costs[13] by the time their capital is paid off. Revenue from state climate policy instruments should be used to support attainment of state climate goals. Providing additional revenue to profitable, privately-owned stations after they have fully recovered their capital is an imprudent use of resources, which could otherwise be directed towards attainment of critical state environmental goals.

[13] Defined as revenue from HRI credits, fuel sales and standard LCFS hydrogen pathway credits being greater than hydrogen procurement costs, O&M costs and interest on debt equal to 100% of capital costs at a 10% interest rate. Hydrogen was assumed to be centrally-produced SMR of natural gas, procurement cost and retail price was taken from CEC's central estimate in http://www.energy.ca.gov/2015publications/CEC-600-2015-016/CEC-600-2015-016.pdf, Figure 20. Retail costs were adjusted downward to reflect a more rapid transition to cost parity with gasoline. Using CEC's retail costs without adjustment would lead to a quicker payback on the station and higher long-term profits.

Excessive HRI credits pose additional risks beyond the LCFS program. Not only is the use of LCFS revenue for fuel-specific infrastructure an abrupt departure from historical LCFS operation, but the level of support is unprecedented, relative to other technology-promoting state subsidy programs for deployment of commercial clean energy products or infrastructure. We are not aware of any other grant or subsidy program which virtually guarantees that State incentives will cover the full cost of capital, much less one that continues to provide support beyond that. The overwhelming majority of similar clean energy programs administered by CARB, CEC and CPUC require developers to retain some exposure to project capital, impose strict limits on rates of return, or often both. The provision of such generous state support under the LCFS case will create a precedent that prospective project developers should expect similar levels of support from other commercial deployment incentives. This

could increase costs for deployment of future clean energy technology and make it more challenging for the state to achieve its climate and air quality goals.

We are also concerned that the proposed HRI provisions complicate or reduce the incentive for hydrogen station owners to reduce the carbon intensity of the fuel they dispense. The current provisions impose a fixed cap on the total number of credits available through HRI pathways. Each station is assigned credits based on a formula which includes the average carbon intensity of hydrogen dispensed by that firm. Higher carbon intensity hydrogen reduces the amount of credit each station receives, but accepting this per-station reduction could allow a firm to have more stations accepted while still staying below the 2.5% aggregate cap. While there are a number of market or competitive factors which impact investment decisions, under some feasible scenarios a firm could obtain more profit by delaying investments in cleaner hydrogen until after 2025 than by making them earlier. This disrupts one of the LCFS's most critical elements: a clear an unambiguous incentive for fuel producers to reduce the carbon intensity of their fuel.

Instructing staff to revisit the appropriateness of an un-capped HRI provision will allow for a re-evaluation informed by capital cost data submitted in the first wave of applications for this program. Existing hydrogen stations will also have provided additional data on operational costs and utilization. With the benefit of additional data, staff can confirm that the existing provisions set an appropriate level of support or make adjustments. It is important that CARB signal its intent to revisit this matter so prospective developers can account for this review in their planning processes. (NEXTGEN4_SF60-14)

> **Agency Response:** The commenter asserts that the HRI provisions in section 95486.2(a) will set a precedent for future infrastructure crediting of other fuels, will cost California fuel consumers millions of dollars per year and will provide a perverse incentive not to reduce capital costs and the CI of dispensed fuel. The HRI provisions will not necessarily result in an increase in cost to fuel consumers, as deficits will not increase as a result of the new credit generation sources. Staff also disagrees that the HRI provisions as written create a perverse incentive not to reduce capital costs and the fuel CI. Industry stakeholders project that capital costs will be reduced significantly through economies of scale as a result of this provision, and staff expects that station owners will take advantage of the advances in technology. In addition, staff disagrees with the commenter that entities will intentionally dispense higher-CI hydrogen in the short-term to maximize credit generation stations approved in the program. Staff see no benefits to pursuing such a strategy.
>
> With regards to the rationale for not including a cap on total HRI revenue per station, please see Response I-2.4, Removal of Cap on HRI Credit Revenue per Station, in this chapter. Staff believes that the commenter has over-estimated revenue per station under the HRI provisions. One major area of concern is the delivered cost of hydrogen assumed by the commenter. The model submitted to the docket assumes delivered costs of hydrogen to start at roughly $8.36/kg and

decline from there. This assumes a CI of 100 g/MJ, which is likely attained through use of landfill biomethane via SMR. This cost estimate is far lower than values supported in the literature and does not include the opportunity cost of not generating RINs for this biomethane, which would likely be reflected in the delivered cost to the station. The best available information to staff estimates that the delivered cost of hydrogen at a CI of 100 is more likely to be on the order of $10-13/kg, which significantly alters the financial outlook for hydrogen providers. In addition, the model submitted in the docket contains the same error identified in the model submitted during the 1st 15-day comment period, in which station revenue from the HRI provisions is calculated assuming that a hard cap is not in place for HRI crediting.

Staff acknowledges that the HRI provision has the potential to provide a large quantity of revenue for hydrogen stations. However, the refueling network goals established by the Governor in Executive Order B-48-18 are equally ambitious and require a significant regulatory support to be achieved. HRI credit generation is capped at 2.5 percent of overall program deficits, and is not expected to significantly impact the credit market. Please see Response I-6.4 in Chapter V regarding this issue.

Staff is committed to ongoing review of the infrastructure crediting provisions, as detailed in Responses to, I-7.3, Ongoing Review of Program Performance" in Chapter V and I-6, Ongoing Review of Performance of Infrastructure Credit Provisions, in this chapter.

I-5. *Requirements to Generate FCI Credits*

I-5.1. Comment: ChargePoint requests clarification on distinguishing between FSEs in instances of colocation. The FCI Pathways encourage colocation but capacity and utilization/throughput cannot comingle. As written, it will be difficult to divvy up credits for the site between different FSEs. One recommendation is that the FCI Pathway Requirements include serial number by the OEM. (CHARGEPOINT4_SF32-4)

Agency Response: Each FSE will be registered individually in the LRT-CBTS, even if the FSE is collocated with other DC Fast Chargers at a site. Each FSE will generate FCI credits based on the nameplate power rating, using the equation listed in section 95486.2(b)(2)(G).

I-5.2. Multiple Comments: Remove Specific Provisions for Payment Protocols to Avoid Preempting SB 454

Comment: ChargePoint strongly recommends against establishing language regarding payment methods that preempt final SB 454 guidelines that will be adopted next year. If the LCFS program preempts or creates a different set of requirements, it could cause confusion, lack of participation in the program, or worse, violations because there are potentially two different sets of language/requirements around payment methods for public stations. Cross-referencing the current rulemaking will make it more streamlined

and easier for EVSE manufacturers and site hosts to meet the requirements. (CHARGEPOINT4_SF32-5)

Comment: (5) The ARB should not preempt final SB 454 guidelines regarding payment methods for the DC Fast Charging Infrastructure ("FCI") Pathways.

…

The Smart EV Charging Group strongly recommends against establishing language regarding payment methods that preempts the final SB 454 guidelines, which we anticipate will be adopted next year. If the LCFS program preempts or creates a different set of requirements, it could cause confusion, lack of participation in the program, or worse, violations because there are potentially two different sets of language/requirements around payment methods for public stations. Cross-referencing the current rulemaking will make it more streamlined and easier for EVSE manufacturers and site hosts to meet the requirements. (SEVCG4_63-6)

> **Agency Response:** In response to stakeholder comment, staff removed specific requirements for payment mechanisms at the FSE, and left only broad language requiring a point of sale method that accepts all major credit or debit cards (if a fee is charged for service). Staff believes that the language included in section 95486.2(b)(4)(C) meets the intent of the provision without preempting potential upcoming rulemakings from different programs within the Agency.

I-5.3. Comment: ChargePoint also requests clarification on Section 95486.2(b)(4)(G). At what point in the project development can a site apply for the FCI pathway? ChargePoint understands that the FCI pathway is only available for new sites, but is asking for clarity on what point in the process applications can be submitted. For example, planning, construction, utility interconnection, or permitting. (CHARGEPOINT4_SF32-6)

> **Agency Response:** An application for FCI charging may be submitted for a FSE that is not permitted to operate prior to January 1, 2019. An entity may submit an application at any point in the development of the FSE. However, the five year crediting window begins at the point of application approval, independent of whether the station is commercially operable.

I-6. Multiple Comments: ***Ongoing Review of Performance of Infrastructure Credit Provisions***

Comment: But we urge the Board to instruct staff in the re-adoption resolution to return to the HRI provisions to evaluate whether the level of support is well targeted and specifically whether an appropriately calibrated cap on the total value of HRI credits would enhance the efficacy of this provision. (UCS4_SF26-5)

Comment: However since it is a significant departure from the traditional LCFS crediting program, PG&E reiterates its recommendation that ARB and stakeholders

carefully monitor the effects of these new capacity crediting programs on the overall LCFS market. (PGE3_SF49-7)

Comment: Finally, SCE supports the many improvements to rules and formulas for the DC fast charging capacity credits and hydrogen station capacity credits, but requests that in a future rulemaking, there be more equity in the design of these two types of capacity credit (e.g. similar sunset provisions).[1] SCE looks forward to working with CARB to continue to enhance the LCFS in future rulemakings.

[1] Instead of the current five years for DC fast charging stalls and fifteen years for hydrogen stations.

(SCE2_SF53-4)

Comment: We wish to call your attention to one element of the current proposal which would institute a counterproductive new provision in the LCFS, and urge you to commit to a thorough ongoing evaluation.

…

As you develop your re-adoption resolution, we urge you to instruct staff to return to the hydrogen station credit provision, and especially the lack of capped credits, at its earliest opportunity to evaluate its merit and efficacy. (ORGS1_SF54-1)

Comment: We are deeply concerned, however, that the proposed infrastructure capacity credits represent an open-ended, inefficient and unnecessary commitment of revenue from the LCFS program, which will ultimately prove counterproductive to the State's climate and clean energy goals. While we recognize that there is insufficient time in the rulemaking calendar to correct these problems without severe disruption to the re-adoption process, we urge the Board to instruct staff to return to this issue at their earliest convenience, to review the early performance of this program and conduct a thorough evaluation of the appropriateness of the levels of support offered by the infrastructure credit provision. (NEXTGEN4_SF60-2)

> **Agency Response:** Staff is committed to ongoing review of the efficacy of the HRI and FCI crediting provisions. Board Resolution 18-34 directs the Executive Officer to, "monitor development of the ZEV Fueling Infrastructure credits under the Low Carbon Fuel Standard, including how those credits impact the business case for such projects, and to propose technical updates as needed." In future rulemakings we may evaluate, among other items: whether instituting a cap on total HRI credit value per hydrogen refueling station would be beneficial for the overall program; the value of harmonizing crediting periods between the two provisions; the appropriateness of levels of support offered by the provisions; and the impact on the overall credit market. With regards to concerns regarding over-crediting of stations, please see Response I-2.4, Removal of Cap on HRI Credit Revenue per Station, in this chapter.

I-7. *General Comments*

I-7.1. Comment: For the HRI pathway, we support the proposed revisions to the 2nd 15-day changes submitted by the California Fuel Cell Partnership on August 24th on

behalf of Air Liquide, FirstElement Fuel, American Honda Motor Co, Inc., Hyundai Kia America Technical Center, Inc., Linde LLC, Mercedes-Benz Research & Development North America, Inc., NEL Hydrogen A/S, Shell New Energies, Toyota Motor North America, United Hydrogen, California Hydrogen Business Council and Energy Independence Now. (AAMGA2_SF18-9)

> **Agency Response:** Please see Responses I-1.1, I-3.1, I-4.1a, I-4.1b and J-13 in this chapter.4a,4a

I-7.2. Comment: In § 95486.2(a)(3)(A), WSPA requests that CARB clarify the difference between Hydrogen Refueling Infrastructure (HRI) credits generated by operational stations in the prior quarter and the total HRI capacity of stations that were operational in the prior quarter as it impacts the estimated potential HRI credits from all approved HRI stations.

In § 95486.2(b)(3)(A), WSPA requests that CARB clarify the difference between DC Fast Charging Infrastructure (FCI) credits generated by operational Fuel Supply Equipment (FSE) in the prior quarter and the total FCI capacity of FSEs that were operational in the prior quarter as it impacts the estimated potential FCI credits from all approved FSEs. (WSPA7_SF29-6)

> **Agency Response:** The equations listed in Section 95486.2(a)(3)(A) and Section 95486.2(b)(3)(A) are used to determine the potential HRI and FCI credits during application review. If Potential HRI or FCI credits exceed 2.5 percent each of the deficits from the previous quarter, staff will wait to approve pending applications until total credits under each respective provision are below this threshold.
>
> HRI and FCI credit generation are directly proportional to the operational capacity of each FSE. In order to project potential credit generation for an upcoming quarter, staff first determines the ratio of current approved capacity to operational capacity in the prior quarter, providing the expected percentage increase in potential hydrogen refueling capacity. Staff then multiplies this ratio by the total HRI/FCI credits generated in the previous quarter to estimate the potential HRI/FCI credits that could be generated in the next quarter.

I-7.3. Comment: In § 95486.2(b)(4)(H), WSPA requests that CARB provide the rationale for choosing the 10% discount rate in the equation to calculate the estimated cumulative value for credits generated in this provision. (WSPA7_SF29-8)

> **Agency Response:** Staff believes that use of a 10 percent discount rate for determining the value of FCI credit revenue is justified. As reasonable points of comparison, staff believes the average utility cost of capital is estimated to be close to 7 percent in the United States and private industry often desires returns in excess of 15 percent for medium risk investments. A 10 percent discount rate is also in line with NREL's assumptions in the H2FAST model used for evaluating the economics of refueling infrastructure.

I-7.4. Comment: In addition to our opposition to these credits on a conceptual level, our July comment letter identified two specific concerns with the proposed language: that the proposed cap mechanism would not limit capacity credits to the intended level and that the mechanism for allocating capacity credits will lead to an excessive and inefficient level of funds to each station, which sends counterproductive market signals and establishes a troubling precedent for future infrastructure support programs.

We would like to thank staff for their constant engagement throughout this process. Their commitment to regular discussion and collaborative work on modeling has certainly improved the state of understanding regarding likely effects of these provisions. Of the two key problems we identified above, one has been effectively resolved in the current proposal, while the other remains deeply troubling. (NEXTGEN4_SF60-13)

Agency Response: Please see Responses I-1.1 and I-4.2 in this chapter.

J. Pathway Application and Carbon Intensity Determination

J-1. *Support for Modifications to the Pathway Application and Carbon Intensity Determination Provisions*

J-1.1. Multiple Comments: *Support for Updating Sorghum Farming Inputs in CA-GREET3.0*

Comment: Finally, we are grateful ARB updated the sorghum farming input values in CA-GREET 3.0. The dataset used in CA-GREET 2.0 was based on USDA surveys in which 75 percent of the years surveyed were severe drought years. This high inclusion of drought years greatly impacted the quality and representativeness of the data and biased the inputs to the high side of reality. In contrast, the updated values currently in CA-GREET 3.0 are based on data from a statistically significant subset of U.S. sorghum farmers and reflect agronomic recommendations at land grant universities. (NSP1_SF15-4)

Comment: Finally, we are grateful ARB updated the sorghum farming input values in CA-GREET 3.0. The dataset used in CA-GREET 2.0 was outdated and needed to be changed. The updated values currently in CA-GREET 3.0 are based on data from a statistically significant subset of U.S. sorghum farmers and reflect agronomic recommendations at land grant universities. Thank you. (CONESTOGA2_SF17-3)

Comment: White Energy would also like to express its appreciation for the updates to the CA-Greet 3.0 model with regards to sorghum. CARB's quick response to the EPA's approval of Sorghum Oil as a feedstock for Biofuel D4 RINs as well as its cooperation with the National Sorghum Producers has shown its commitment to maintaining the programs integrity and synergies with other renewable fuels programs. (WE4_SF20-3)

> **Agency Response:** Staff appreciates the support for CARB's update of sorghum farming input values in CA-GREET3.0.

J-1.2. *Support for Corrections in the CA-GREET3.0 Model*

Comment: *Modifications to the GREET Model.* As an initial matter, Growth Energy appreciates CARB staff's recommended modifications to the GREET model. Among other things, CARB has clarified its treatment of haul and backhaul emissions, corrected issues concerning medium and heavy-duty truck emissions, and corrected its calculation of the nitrogen content for sugarcane ethanol. (GROWTHENERGY3_SF31-1)

> **Agency Response:** Staff appreciates the support for corrections in the CA-GREET3.0 model for medium- and heavy-duty truck emissions and nitrogen content in sugarcane straw.

J-1.3. ***Support for Updates to Transportation by Rail and Barge***

Comment: Thank you for considering our comments concerning the removal of backhaul emissions, and clarifying that the energy intensities CARB is using are for the haul and backhaul combined. (GROWTHENERGY3_SF31-9)

> **Agency Response:** Staff appreciates the support for updates and clarification to transportation by rail and barge.

J-1.4. ***Support for Updates to Fuel Economy***

Comment: Thank you for considering Growth Energy's prior comments concerning medium and heavy-duty truck emissions, and in particular, recognizing that the fuel economy of both vehicle classes were too low and that the fuel economy for the backhauls should be better than the haul. (GROWTHENERGY3_SF31-10)

> **Agency Response:** Staff appreciates the support for updates to fuel economy for medium- and heavy-duty trucks. Staff also appreciates support for addressing fuel economy differences between fully-loaded and empty back-haul for both medium- and heavy-duty trucks.

J-1.5. ***Support for Updating Nitrogen Content of Sugarcane Straw***

Comment: Thank you for considering Growth Energy's comments on the nitrogen content of sugarcane straw and increasing this value from 0.37% to 0.53%, based on the average value from several literature sources, instead of just the lowest value. (GROWTHENERGY3_SF31-11)

> **Agency Response:** Staff appreciates support for updating nitrogen content of sugarcane straw based on the average value from literature sources cited in the GREET1_2016 version of Argonne's model.

J-1.6. ***Support for the Inclusion of Book-and-Claim Accounting for Biomethane Delivery***

Comment: In past comment letters, DTEBE has expressed our desire to allow book-and-claim delivery for all biomethane used to generate LCFS credits, including biomethane used for renewable hydrogen production, innovating refinery projects, or as a process fuel. DTEBE thanks CARB for addressing this issue in the most recent amendment package, including 95488.8(i)(2). Allowing the ubiquitous use of book-and-claim accounting for biomethane delivery encourages a broad utilization of RNG to provide carbon intensity reductions in California. (DTEBE3_SF19-3)

> **Agency Response:** Staff appreciates support for inclusion of language to allow book-and-claim biomethane delivery in the amendment package.

J-2. *CA-GREET3.0 Model*

J-2.1. *Errors in the CA-GREET3.0 Model*

Comment: Review of the August 13, 2018 release of the CA-GREET 3.0 Technical Support Documentation indicates that a number of uncertainties and potential errors exist in the document as written. On August 28, 2018, CARB posted an Errata where CARB staff corrected errors in the CA-GREET3.0 model and five of the simplified calculators. Because of the late release of Errata, WSPA has yet to review the revised CA-GREET 3.0 Technical Support Documentation. Therefore, WSPA will be contacting CARB staff in the near future to discuss areas of concerns and possible remaining clarifications/corrections. (WSPA7_SF29-16)

> **Agency Response:** The errata released on August 28, 2018 addressed and corrected only typographical errors in Excel formulas or in the text from the CA-GREET3.0 model and five Simplified CI Calculators. The errata, however, did not change the LCA methodology or the second 15-day updated technical documents.

J-2.2. Multiple Comments: *Distillers Grains Enteric Fermentation Credit*

Comment: That said, there are still several issues with the GREET model that should be modified to ensure the LCFS is based on "the best available economic and scientific information." (Health & Saf. Code, § 38562, subd. (e).) In addition to the unresolved issues raised previously by Growth Energy, GREET should be revised to include a distillers grains enteric fermentation credit for corn ethanol, and ensure that the credit is based on conditions in the United States (in contrast to Hünerberg, *et al.*). (See Exhibit "A"). (GROWTHENERGY3_SF31-2a)

Comment: In this latest version of the Proposed Modifications to the LCFS, CARB still did not include a distillers grains enteric fermentation credit for corn ethanol. CARB, however, in their Errata document listed a new reference:

> Feeding high concentrations of corn-dried distillers' grains decreases methane, but increases nitrous oxide emissions from beef cattle production, Agricultural Systems 127 (2014): 19-27. Hünerberg, M., Little, S.M., et al., Available at: https://www.sciencedirect.com/science/article/pii/S0308521X14000146?via%3Dihub.

This reference was included presumably to counter our prior comment about reduced methane from cattle fed dried distillers grains (DDGs). As the title indicates, the article is presenting evidence that N_2O emissions increase with cattle fed DDG, and that this increase in N_2O emissions negates the reduced methane emissions (i.e., enteric fermentation credit). The increase is due to higher emissions of N_2O from cattle manure when fed either corn DDGs or wheat DDGs. The article indicates:

> Using high-fat distillers grains in the diet of feedlot cattle may decrease enteric CH_4 emissions, but *at high dietary levels* it increases N excretion and results in a net increase in GHG emissions *(emphasis added)*.

However, in reviewing the article, it is apparent that the evidence presented is not applicable to the U.S. Specifically, the evidence is based on cattle fed with 40% DDGs, which does not reflect U.S. conditions. This is also inconsistent with the assumptions in Argonne's GREET model, which assumes a DDG dietary inclusion rate of 22-23%, about half of the amount used in a case study described in this article.[1] The inclusion rate would have a direct effect on N_2O emissions. Using a much lower DDG inclusion rate than 40% would result in no increase in N_2O emissions from cattle fed DDGs. Thus, because the experiment conducted in this research is not applicable to the inclusion rates in the U.S., CARB should include the enteric fermentation credit in CaGREET2.0.

[1] *Update of Distillers Grains Displacement Ratios for Corn Ethanol Life-Cycle Analysis*, Arora, S., Wu, M., and Wang, M., Energy Systems Division, Argonne National Laboratory, September 2008, ANL/ESD/11-1. See Table 11 of this report for dietary inclusion rates in the U.S.

(GROWTHENERGY3_SF31-8)

Comment: We appreciate the fact that CARB has incorporated some of our prior comments on the GREET model. However, in order to be consistent with the best available scientific data, the GREET should be further modified to incorporate all of our prior comments. In summary, the latest version of the GREET model should be modified to include the DG enteric fermentation credit for corn ethanol.

Attachment 1

Biodiesel CIs from CaGREET2.0 Versions

Mar-18	**Corn Oil from DGS of Dry Mill Ethanol to Biodiesel**									
	g/MMBtu	Corn oil Extraction	Corn Oil Transport	Corn oil Debit	BD production	BD T&D	Total CI	Tank-to-Wheel	LUC	Final CI, g/MJ
	VOC	0.36	0.19		2.40	0.96	3.90			3.90
	CO	1.46	0.62		5.75	3.15	10.98			10.98
	CH4	6.35	1.28		37.07	3.62	48.32			48.32
	N2O	0.06	0.00		0.18	0.03	0.27			0.27
	CO2	2982.07	552.48		11148.76	1619.74	16303.05			16303.05
	Subtotal gCO_2e/MJ	**3.00**	**0.56**	**11.17**	**11.51**	**1.64**	**27.87**	**0.76**	**0.00**	**28.63**
	Adjustment	**2.84**	**0.53**	**10.59**	**10.92**	**1.64**	**26.52**	**0.76**	**0.00**	**27.28**
Jul-18	**Corn Oil from DGS of Dry Mill Ethanol to Biodiesel**									
	g/MMBtu	Corn oil Extraction	Corn Oil Transport	Corn oil Debit	BD production	BD T&D	Total CI	Tank-to-Wheel	LUC	Final CI, g/MJ
	VOC	0.36	0.19		2.40	0.96	3.90			3.90
	CO	1.46	0.62		5.75	3.15	10.98			10.98
	CH4	6.35	1.28		37.07	3.62	48.32			48.32
	N2O	0.06	0.00		0.18	0.03	0.27			0.27
	CO2	2982.07	552.48		11148.76	1619.74	16303.05			16303.05
	Subtotal gCO_2e/MJ	**3.00**	**0.56**	**11.17**	**11.51**	**1.64**	**27.87**	**0.76**	**0.00**	**28.63**
	Adjustment	**2.84**	**0.53**	**10.59**	**10.92**	**1.64**	**26.52**	**0.76**	**0.00**	**27.28**
Aug-18	**Distiller's Corn/Sorghum Oil from DGS of Dry Mill Ethanol to Biodiesel**									
	g/MMBtu	Distiller's oil Extraction	Distiller's Oil Transport	Distiller's oil Debit	BD production	BD T&D	Total CI	Tank-to-Wheel	LUC	Final CI, g/MJ
	VOC	0.36	0.20		2.39	0.96	3.91			3.91
	CO	1.46	0.68		5.73	3.16	11.02			11.02
	CH4	6.34	1.09		37.02	3.32	47.77			47.77
	N2O	0.06	0.00		0.18	0.03	0.27			0.27
	CO2	2980.62	452.10		11124.00	1472.30	16029.02			16029.02
	Subtotal gCO_2e/MJ	**3.00**	**0.46**	**11.26**	**11.49**	**1.49**	**27.69**	**0.76**	**0.00**	**28.45**
	Adjustment	**2.84**	**0.43**	**10.68**	**10.89**	**1.49**	**26.34**	**0.76**	**0.00**	**27.10**

(GROWTHENERGY3_SF31-12)

Agency Response: Staff does not agree with the commenter's statement that lower inclusion rates of DGS will not result in an increase in N excretion rates. Literature evidence reviewed to assess commenter's statement supports staff's position. For example, a U.S.-based case study of 2,000 heads of beef cattle fed diet containing 0, 20 and 40 percent DGS reported that nitrogen content in the cattle manure increased by 21 percent to 51 percent for DGS at 20 and 40 percent inclusion rates, respectively; furthermore, when compared to the Natural Resources Conservation Service (NCRS) Book Value of the nitrogen concentration in cattle manure, the nitrogen content in the excretion increased by 44 percent to 81 percent for DGS at 20 and 40 percent inclusion rates, respectively.[62] For reasons detailed in response J-2.2 in Chapter IV, there is no credit for reduced enteric fermentation emissions due to the inclusion of DGS in livestock rations in LCFS ethanol pathways.

Staff is also unable to respond to the table presented in the "Attachment 1" because (1) this table (or any value listed) is not referenced anywhere in the comment letter, (2) the model name, "CaGREET2.0", used in the table caption (and the comment) is not applicable to the current amendments, and (3) the "Attachment 1" does not indicate what the commenter is trying to convey with the provided information.

J-2.3. Multiple Comments: *User-Defined Fields in CA-GREET3.0*

Comment: EcoEngineers believes that having a strong verification program should allow CARB to put more user-defined fields in CA GREET 3.0. CARB should allow for a basic set of farm practices fields, including yield, nitrogen use, farming energy and transport distance of feedstock, to become user-defined fields in the GREET model. From our estimates, the modification of the above farm practice inputs could lower the CI score up to 15 to 20 CI points for a corn ethanol facility.

These fields should be modified only when a farm practices verification plan is completed by the reporting party. This change would allow a renewable fuel producer to incentivize local farms to lower GHG emissions from agriculture and produce low carbon intensity fuel from agricultural feedstock. (ECOENGINEERS3_SF22-10)

Agency Response: The default input parameters in the CA-GREET3.0 model represent the collective practices of farms supplying feedstock to renewable fuel producers. Extensive research has gone into the values proposed in the CA-GREET3.0 model as well as the Simplified CI Calculators that enable the determination of the fuel pathway CI.

Agricultural input parameters in the CA-GREET3.0 model are derived from well-documented, published work by the United States Department of Agriculture

[62] Regassa T, Koelsch R, Erickson G. Impact of Feeding Distillers Grains on Nutrient Planning for Beef Cattle Systems. University of Nebraska-Lincoln Extension RP190. http://extensionpublications.unl.edu/assets/pdf/rp190.pdf

and other federal, state and international agencies. To consider individual farm-level data as user-defined inputs as suggested by the commenter would entail significant burden on staff to develop robust verification and monitoring methodologies. Therefore, staff at the present time, did not propose the inclusion of farm-specific inputs for CI calculations. Please see also Response J-4.6a, Soil Carbon Effects Associated with Corn Production, in Chapter IV.

J-3. *Simplified CI Calculator for Starch and Fiber Ethanol*

Comment: We are also hopeful ARB will continue moving toward allowing grain sorghum fiber to be used as a feedstock to produce cellulosic biofuels. The feedstock is approved under RFS2, and many ethanol plants are considering this option. For this reason, it is important for market liquidity and fungibility any of these gallons that move into California have a ready market. Like corn fiber, grain sorghum fiber is almost exclusively cellulose, and it is found in similar quantities in grain sorghum. For this reason, there will be no practical differences between the two feedstocks from a GHG perspective. (NSP1_SF15-3)

Agency Response: Staff has incorporated sorghum fiber ethanol in the August 13, 2018 version of the Tier 1 Simplified CI Calculator for Starch and Fiber Ethanol.

J-4. *Simplified CI Calculator for Sugarcane-Derived Ethanol*

J-4.1. Comment: The mills at South-Central region of Brazil has increase significantly its harvest mechanization percentage over the last decade. The increase in São Paulo state was supported by the commitment, Green Ethanol Protocol, of the mills to eliminated pre-harvest field burning in 2017. The actual mechanization percentage in South-Central region of Brazil is higher than the default values proposed for the calculator, 80% for São Paulo state and 65% for other states in the Center-South region.

In this way, Copersucar urges that CARB include an option for self-declared mechanization percentage in the tier 1 CI calculator, so the calculator would have 2 options: to use a default mechanization value or input the site-specific values. Due to the high mechanization percentage, we would prefer to prove that we have a highest level as this has a significant impact on the CI value.

These update consider the reality of sugarcane mechanization practices in Brazil. (COPERSUCAR1_SF43-1)

Agency Response: Please see Response J-5.9 in Chapter IV.

J-4.2. Comment: While we recognize the effort of staff to make the pathway registration process more efficient, we are concerned that sugarcane ethanol will not be scored accurately under the proposed changes. Given the short 15-day comment period, the comments below are not exhaustive. However, UNICA has attempted to identify some of the most important problems with the way the new CI calculator will

score sugarcane ethanol. We respectfully request that the Board and ARB staff carefully consider these comments and also consider the letter of suggestions[6] UNICA delivered at the last Board meeting on April 23rd. In both documents, we believe we have included valuable and important suggestions that need to be implemented in order to help California accurately capture the reality of the sugarcane ethanol industry in Brazil and reap the benefits of this low carbon biofuel. **We urge you to take them into consideration before finalizing any adoption of amendments.**

[6] UNICA's letter to CARB of April 23, 2018: https://bit.ly/2KJFEKO

(UNICA4_SF30-1)

Agency Response: Staff thanks the commenter for their input. We assure UNICA that we have taken their comments into consideration, as we do for all stakeholder comments.

J-4.3. Comment: UNICA and its member companies are very concerned about the way the proposed simplified calculator would treat the mechanization input. Our members have made significant investments over the past decade to reduce emissions through the mechanization process, and they should be allowed to reap the benefit of this investment by inputting site-specific mechanization data into the calculator. When UNICA and its members companies began liaising with ARB staff on this issue, we understood that mills would either opt to use a default lower mechanization value and avoid verification, or mills would input their site-specific values and go through verification. These conversations evolved, and we submitted on April 23rd our suggested methodology for mechanization verification. Our July 5th comments[7] again urged CARB to include a site-specific mechanization input in the Tier 1 calculator. We later learned that CARB does not intending to include this input with the calculator. We urge ARB to reconsider this decision so that biofuel producers who have invested in modern (and expensive) technology are not penalized by lower default assumptions.

[7] UNICA's letter to CARB of July 5, 2018: https://bit.ly/2MvNyt2

The South-Central region of Brazil—which is responsible for all the ethanol exported from Brazil to countries such as the United States, Japan and the European Union—has seen dramatic increases in mechanization over the last decade. According to the State-owned Brazilian Food Supply Company (CONAB in Portuguese), from the Brazilian Ministry of Agriculture, Livestock and Food Supply (MAPA), the South-Central region has reached 95.6% of mechanization level in 2017/2018 crop year, compared to 28.5% one decade ago.[8] Indeed, this index is even higher according the Sugarcane Technology Center (CTC), which estimated that mechanical harvesting in areas owned by mills in South-Central region reached 98% in the named season. For the current 2018/2019 harvest CONAB estimates 97% mechanization in the South-Central region.[9] This increased mechanization has coincided with a period of increased production. According to the same CONAB report, the increase of sugarcane harvest in Brazil since the 2007/2008 harvest was of 359.6%, meaning some 4,391 more harvests in the field.[10]

[8] http://www.conab.gov.br/OlalaCMS/uploads/arquivos/17_08_24_08_59_54_boletim_cana_portugues_-_2o_lev_-_17-18.pdf (page 60)

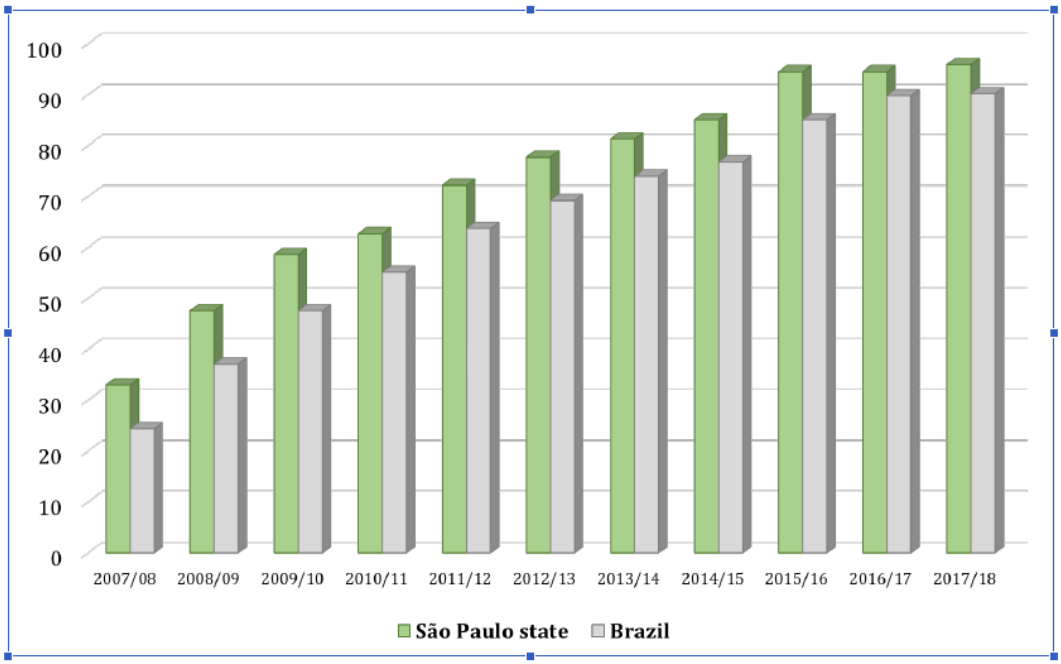
[9] Boletim Cana 2 Levantamento 18/19 (page 55): https://bit.ly/2wiZrYb

[10] Boletim Cana 2 Levantamento 18/19 (page 56): https://bit.ly/2wiZrYb

As CARB is aware, São Paulo state government, in partnership with UNICA and sugarcane growers association (ORPLANA), created in 2007 a Green Ethanol Protocol, a pioneer initiative that, among other commitments, eliminated pre-harvest field burning in 2017. According to the Environmental Secretary, 95% of all sugarcane processed in the São Paulo state is under the management of certified parties.[11] Since June 2017 this commitment has entered into a new phase, now called More Green Ethanol Protocol, that continues to reiterate the pre-harvest field burning commitment, but includes the important commitment of restoring riparian vegetation around cane fields.

11 Slide 3 of the document: http://arquivos.ambiente.sp.gov.br/etanolverde/2017/06/etanol-verde-relatorio-preliminarsafra-16_17-site.pdf

Sugarcane Harvesting– Fast Mechanization Process in Brazil



Source: CONAB (National Supply Company, from the Brazilian Ministry of Agriculture, Livestock and Food Supply

As previously mentioned, our industry has invested a great deal in mechanization in the sector in the last decade. These investments helped the sugarcane sector reduce GHG emission from harvesting by 57% over the past 10 years (from 4.8 to 2.1 g CO_2eq/MJ of ethanol), considering the parameters given in Table 1. We believe there is strong evidence that the soil carbon stocks increase due to unburned mechanized harvesting.[12] Estimations from Figueiredo and La Scala Jr (2011)[13] indicate that the emissions in the mechanized harvesting are almost 1500 kg CO_2eq ha^{-1} $year^{-1}$ lower than those for the burned harvesting, since it leads to a soil carbon sequestration of more than 1170 kg CO_2eq ha^{-1} $year^{-1}$.

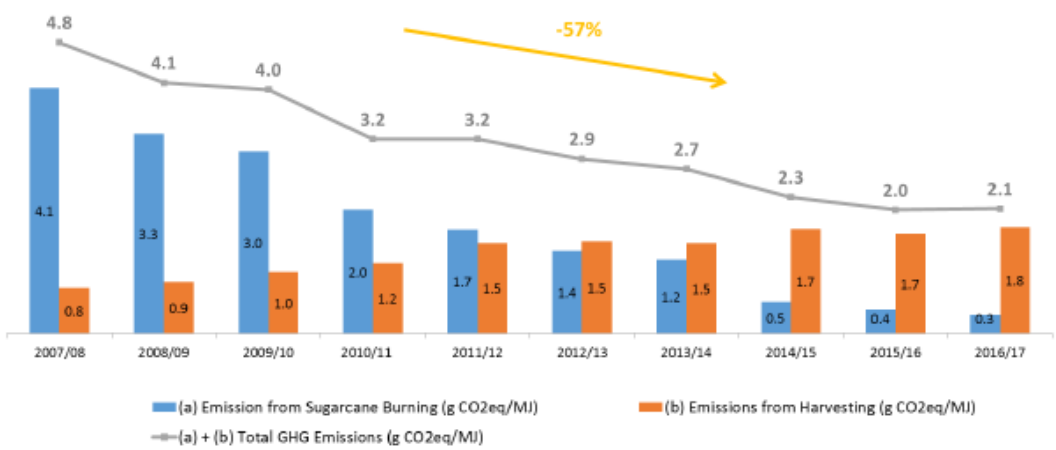
12 Cerri, C. C., Galdos, M. V., Maia, S. M. F., Bernoux, M., Feigl, B. J., Powlson, D. and Cerri, C. E. P. European Journal of Soil Science; Special Issue: Soil Organic Matters; Volume 62, Issue 1, pages 23–28, February 2011

[13] Figueiredo EB, La Scala Jr N. Greenhouse gas balance due to the conversion of sugarcane areas from burned to green harvest in Brazil. Agriculture, Ecosystems and Environment 141 (2011): 77-85

Table 1: Parameters used for the estimation of emissions balance between burned and mechanized harvesting

Parameter	Value/source
% Mechanized harvesting	CONAB
Sugarcane production	UNICA
Sugar and ethanol production	UNICA[11]
Straw burning emissions	2.7 kg CH_4/t dry matter burnt 0.07 kg N_2O/t dry matter burnt[12]
Straw to cane stalk ratio	140 kg (dry basis) per tonne of stalk
Harvester's diesel consumption	74 L/ha
Life cycle diesel emissions	83.8 g CO_2eq/MJ

Emissions Balance (Burning vs. Mechanization)



In the CI calculator for sugarcane ethanol, CARB proposes two default values for sugarcane mechanization for Brazil: 80% for São Paulo state and 65% for other states in the Center-South region. Although some of UNICA's members would probably opt

for using the default value, the vast majority of our members—especially those located in Sao Paulo, where nearly all sugarcane harvesting is mechanized—would prefer to prove that they are at highest levels of mechanization.

A good example of how a low default mechanization value hurts Brazilian sugarcane ethanol's CI is the recent increase of the emissions related to straw burning from 10.06 to 12.04. In practical terms this means that each 10% of mechanized harvest is worth 1.2 CI points. By forcing mills to use a default mechanization value of 80%, CARB is denying 2.4 points of CI for mills who have 100% mechanized harvest.

UNICA continues to urge that CARB include an option for self-declared mechanization percentage in the tier 1 CI calculator. If Staff feels that variable input for this factor is not feasible, we urge that the Board not approve this version of the calculator until staff adjust the default mechanization values for Center-South Brazil to a value no lower than 85% and to Sao Paulo State to a value no lower than 95%. By doing so, staff will be scoring this input more closely to actual practice and will most likely be spared from having to go thru multiple Tier 2 applications requests from the hundreds of Brazilian mills registered with CARB.

UNICA member mills, who represent the vast majority of Brazilian mills registered with CARB, are highly sophisticated enterprises who invest a great deal in the automatization of their agricultural and industrial processes. Third party verifying bodies in Brazil have, for years, audited mills' systems for certification schemes like the Bonsucro, EPA's RFS program and the LCFS itself. We encourage CARB staff to continue to reach out to verification companies in Brazil, as well as to regulatory agencies in the country, in order to clarify doubts or misunderstanding regarding the automatized systems used by sugarcane mills.

We believe these updates are not only the best way to capture the reality of sugarcane mechanization practices in Brazil, but also the fairest approach to allow Brazilian ethanol to compete in the Californian market. (UNICA4_SF30-2)

> **Agency Response:** For sugarcane ethanol applications from Brazil certified through 2018, estimation of mechanized harvest fractions entailed significant staff-applicant interactions over extended periods of time. Each application historically has required several weeks of review to ensure staff had necessary data to estimate a mechanized harvesting fraction. At times this led to delays in pathway certification (for all applications) due to the resource commitments required to process sugarcane ethanol pathways.
>
> To expedite pathway certification for sugarcane ethanol pathways under the new rule, staff included standard mechanized harvest fractions (80 percent for Sao Paulo state and 65 percent for non-Sao Paulo states) which would not require either staff or third-party verification. These fractions were developed using data from hundreds of sugarcane ethanol applications certified in the period 2014 through 2018. Although some applicants have demonstrated higher mechanized

harvest fractions, staff has observed that mechanized harvest fractions drop dramatically during drought years (i.e., 2014 was one such year) in Brazil. Staff developed the standard values (80 percent and 65 percent) since they provide reasonable assurance that harvest fractions do not dramatically drop during drought years in Brazil. As for impacts on carbon intensity (CI) for mills which claim to source from regions with higher harvest fractions, staff has determined that changes are generally less than 1 g/MJ for such pathway applicants. Staff believes that the marginal decrease in CI does not justify the significant burden of validating (by CARB staff or third-party verifiers) that harvest fractions are higher than the standard value. The Tier 1 calculators, therefore, do not include the option to specify farm-specific mechanized harvesting fractions. Please see also Response J-5.9 in Chapter IV.

J-4.4. Comment: UNICA is very concerned that CARB staff continue to advocate for the inclusion of back-haul penalties for maritime transportation of sugarcane ethanol to California. We have not seen any data to support CARB's assertion that ocean tankers bringing ethanol fuel from Brazil to California will necessarily return empty to Brazil. From conversations with staff, we understood that this back-haul emission penalty is due to a conservative approach staff wants to take in case such empty return trips happen in the future. We decided to verify our observations that ethanol ships from Brazil do not return empty and shared our findings with staff in the Exhibit C of our April 23, 2018 letter.[14]

[14] UNICA's Letter to CARB of April 23, 2018, pages 23-32: https://bit.ly/2KJFEKO

As the maps showed, in the past two years, nine ships have brought ethanol from Brazil to California, for a total of 10 trips (vessel High Valor has made the trip twice). From California, these vessels called other ports to deliver other products. The tracking of these vessels confirmed our observations that ships do not necessarily go back to Brazil, and certainly not empty. Out of 10 trips, only one was back to Brazil, with the vessel carrying diesel. All other nine trips were to Asia, Europe, and Mexico.

Contrary to what CARB staff had mentioned during our conversations, back-haul penalty is not minimal for sugarcane ethanol. Our mills ran a comparison of CA-GREET 2.0 and CA-GREET 3.0 (images below) models and found out that an average exporting mill would have its CI increased by 3.5 points due to this penalty.

CA-GREET 2.0 (CI results in red):

Transportation and Distribution			7,78
From ethanol plant to port	HDD Truck		
Shares	100%		
Miles	244		
From ethanol plant to port	Pipeline		
Shares	100%		
Miles	0		
From ethanol plant to port	Rail		
Shares	100%		
Miles	0		
From port to CA port	Ocean Tanker		
Shares	100%		
Miles	8.953		
From CA port to blending terminals	HDD Truck		
Miles	40		
From terminals to fueling stations	HDD Truck		
Miles	50		

CA-GREET 3.0 (CI results in red):

Ethanol Transport and Distribution			11,36
From Ethanol Plant to Brazil Port *Miles*	Mode: HDD Truck 244	68642343,2850547 dry gals	
From Brazil Port to California Port *Miles*	Mode: Ocean Tanker 8.953	100%	
From California Port to Blending Terminal *Miles*	Mode: HDD Truck 40	100%	
California Blending Terminal to Refueling Station *Miles*	Mode: HDD Truck 50	100%	

Maritime transportation would certainly not be efficient and affordable if vessels travelled empty around the world. Assuming that the energy consumption and associated emissions of the ocean tanker's round trip be attributed to sugarcane ethanol is speculative and arbitrary, and causes a tremendous impact in sugarcane ethanol competitiveness in the California market. **We urge staff <u>not</u> to impose back-haul penalties on Brazilian sugarcane ethanol, since these penalties are not supported by current market and trading practices. Additionally, UNICA would like to request that staff make available the evidence CARB has obtained to justify the imposition of such penalty on sugarcane ethanol.** (UNICA4_SF30-3)

Agency Response: A recent report[63] on maritime transport estimated that a minimum of 45 percent of ocean freight carriers return empty after delivering freight to their intended destinations. To ensure the manifest of each and every ocean tanker loaded with sugarcane ethanol transported from Brazil to California

[63] Geography, search frictions and endogenous trade costs, (No. w23581). National Bureau of Economic Research. Brancaccio, G., Kalouptsidi, M., & Papageorgiou, T. (2017).

is verified (both inbound and return) places a burden on both third-party auditors and staff. This is further complicated if tankers do not return to their original port where the fuel was loaded. Also, since all fuel pathways are being assessed back-haul emissions, to ensure equitable treatment for all fuels, staff is including back-haul emissions for ocean tankers transporting sugarcane-derived ethanol to California. Please see also Response J-5.11 in Chapter IV and response to UNICA3_FF38-2 in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

J-4.5. Comment: ARB staff also included the use of yeast in sugarcane ethanol production, resulting in an additional 3.34 g CO2e/gallon of ethanol. In sugarcane ethanol production, yeast is supplied in the beginning of the production cycle, then recovered and reused in the fermentation process throughout the year.[24] At the end of the processing year, this recycling strategy tends to reduce yeast usage to virtually zero. The document provided by ARB staff fails to provide the scientific reason to change the (correct) assumption of GREET 2.0. Accordingly, UNICA respectfully requests that CARB retain the assumption reflected in GREET 2.0.

[24] Marina Oliveira de Souza Dias a,n , Rubens Maciel Filho b , Paulo Eduardo Mantelatto c , Otávio Cavalett c , Carlos Eduardo Vaz Rossell c , Antonio Bonomi c , Manoel Regis Lima Verde Leal **Sugarcane processing for ethanol and sugar in Brazil.** Environmental Development 15 (2015) 35–51.

(UNICA4_SF30-5)

Agency Response: Staff believes that UNICA has misinterpreted GHG impacts for yeast usage in CA-GREET3.0. The model considers only a starter batch of yeast required at the commencement of a production cycle with additional yeast being generated by self-propagation. The value for yeast usage is **3.34 grams of yeast** per gallon of ethanol and not 3.34 gCO_2e per gallon of ethanol as stated by the commenter. This value was calculated from data submitted by sugarcane-ethanol applications and corroborated from Wang et al.[64] The net impact from yeast usage is estimated to be 0.10 gCO_2e/MJ for this pathway.

J-4.6. Comment: The methodological decisions commented above have clear economic and commercial impacts. UNICA used the CA-GREET 3.0 model to simulate such impacts into sugarcane ethanol CI values. For such, we have considered how these decisions impact the CI of a theoretical mill outside Sao Paulo state, in center-south of Brazil that has about 95% of sugarcane mechanically harvested and exporting electricity to the grid.

As mentioned above, proposed regulation does not allow to input site-specific mechanized harvesting data in Tier 1, so it would have to use the default value of 65%.[25] In that case and considering all other parameter of CA-GREET 3.0, the ethanol

[64] Wang et al, 2012. "Well-to-wheels energy use and greenhouse gas emissions of ethanol from corn, sugarcane and cellulosic biomass for US use," Environ. Res Lett, 7, 045905. Available at: http://iopscience.iop.org/article/10.1088/1748-9326/7/4/045905/pdf

CI would be about 4g CO2e/MJ higher than the actual value. Considering other changes not listed in this letter (yeast usage, and back-hall emissions in oceanic transport), observed CI would be at least[26] 8g higher than correct one.

[25] Please refer to documents from UNICA providing verification methods on such aspect.

[26] Sensitivity analysis for marginal electricity and other N_2O emissions from straw burning was not performed due to lack of time.

Considering current average carbon prices in the 2018 LCFS program, such decisions results in an additional significant burden of about 24 cents per gallon. This additional burden, at the end of the day, results in unnecessary costs for Californian citizens, and distorts the market for low-carbon fuels by undervaluing Brazilian sugarcane ethanol relative to its climate benefits. Left unchanged, these decisions will ultimately dampen investment in our industry, potentially reducing the supply of low-carbon fuels to California. (UNICA4_SF30-6)

> **Agency Response:** Staff does not agree with commenter that Brazilian ethanol is assessed an additional burden. Staff has reviewed feedback from the commenter and has justified the life cycle analysis used for sugarcane ethanol pathways (e.g., standard mechanization percentages, back-haul emissions, yeast usage emissions). Staff estimates the CI impact of not assessing 100 percent mechanization to a pathway are significantly lower than those provided by the commenter (please see Response J-4.3 in this chapter). Staff has also clarified that the GHG impacts of inclusion of yeast usage is approximately 0.10 g/MJ, and not 3.34 g/MJ as suggested by the commenter (please see Response J-4.5 in this chapter). In summary, staff does not agree with the commenter's assessment that the CI for sugarcane ethanol increases by 8 g/MJ and the corresponding 24 cent penalty when using the Simplified CI Calculator. Benefits accruing to the fuel producer are directly correlated to CIs calculated using a consistent life cycle analysis approach for all fuels. Please see also Response J-4.4 in this chapter regarding back-haul emissions.

J-4.7. Comment: UNICA understands and supports CARB's desire to enhance the LCFS. We want to make sure that the proposed amendments have their intended effect and allow more low-carbon sugarcane ethanol to reach Californian ports and gas tanks. To accomplish this goal, CARB needs to revisit the sugarcane calculator. We urge the Board to consider and implement our suggestions and ensure that sugarcane ethanol is fairly scored in the GREEET-CA 3.0 modeling, so that Californian consumers can continue to reap the benefits of sugarcane ethanol. We are at staff's disposal to work on any aspect of our suggested modifications, or to provide any additional data from the current experiences and anticipated trends in Brazil. (UNICA4_SF30-7)

> **Agency Response:** Staff appreciates the support related to the LCFS amendments. For response to comments related to revisiting the sugarcane ethanol calculator, please see Responses J-4.2, J-4.3, J-4.4, J-4.5, J-4.6, and J-4.8 in this chapter.

J-4.8. Comment: From previous conversation with CARB staff, we understand that the agency intends to discount electricity credits generated from straw (or sugarcane

residues – leftover fibers, stalks and leaves) for all sugarcane ethanol pathways. Our understanding is that the technical basis for such a move is the belief that straw removal from the field may influence the need for supplementary use of nitrogenous fertilizers (N-Fert).

We agree that this is an important issue for carbon footprint calculation considering the outsized role N-Fert has in overall GHG emissions from biofuels. Given the importance of this issue for the LCFS program and for Brazilian sugarcane ethanol producers, we encourage CARB to perform a detailed analysis that better reflects the practice in Brazil, accounting for straw emissions and credits in a more complete manner prior to making these amendments. In the following paragraphs, we provide a summary of the most relevant literature on the subject.

Vitti et al.[15] (2007) concluded that Nitrogen (N) and Sulfur (S) stocks of root system are positively correlated with sugarcane yield in the next crop. Figueiredo (2011)[16] indicates that in green-harvested areas, 1619.8 $kgCO2e.ha^{-1}$ are emitted into the atmosphere each year, mainly due to fertilization and diesel use. However, it is worth noting that the results heavily depend on the site-specific characteristics. Fortes et al. (2012)[17] points out those sugarcane postharvest residues is an important source of carbon and nutrients to soil-plant system. In a recent literature review, Carvalho et al. (2017)[18] argue that the indiscriminate removal of crop residues can reduce the environmental benefits of bioenergy. The same study indicates that benefits in soil carbon (C) stocks were reduced when total aboveground residue was removed while partial removal of sugarcane residues did not reduce soil C stocks.

[15] Vitti, A.C. et al., (2007). Produtividade da cana-de-açúcar relacionada ao nitrogênio residual da adubação e do Sistema radicular. Pesquisa Agropecuária Brasileira. Brasília, v.42, n.2, p. 249-256.

[16] Figueiredo, E.B. (2011). *Greenhouse gas balance due to the conversion of sugarcane areas from burned to green harvest in Brazil. Agriculture, Ecosystems and Environment* 141. p. 77-85.

[17] Fortes, C. et al. (2012). *Long-term decomposition of Sugarcane harvest residues in São Paulo state, Brazil. Biomass and Bioenergy* 42. p. 189-198.

[18] Carvalho, J.L.N. et al. (2017). *Contribution of above and belowground bioenergy crop residues to soil carbon. Global Change Biology – Bioenergy.*

However, it is recognized that nitrogen from plant residues goes through complex processes, involving several paths to N_2O, leaching to groundwater and surface water trapping, as well as direct emissions of the soil as N_2O, leaving a small fraction for effective use in the cultivation of the plant. Evidences from Vitti et al. (2008)[19] and Vitti et al. (2011)[20] show that nitrogen from straw does not contribute to sugarcane nutrition and that N from straw is below 1%.

[19] Vitti, A.C. et al., (2008). Mineralização da palhada e crescimento de raízes de cana-de-açúcar relacionados com a adubação nitrogenada de plantio. Revista Brasileira de Ciência do Solo. 32:2757-2762, Número Especial.

[20] Vitti, A.C. et al., (2011). Nitrogênio proveniente da adubação nitrogenada e de resíduos culturais na nutrição da canaplanta. Pesquisa Agropecuária Brasileira. V. 46, n. 3, p.287-293. Brasília – São Paulo, Brasil.

Recent literature corroborates that **there are levels for soil straw removal, with little or no impact on the need for nutrient replacement**. Neto (2015)[21] points out that the presence of different amounts of sugarcane straw did not change N_2O emissions relative to bare soil (control). In an extensive literature review, Carvalho et al. (2016)[22]

verifies that crop residues remaining on sugarcane fields provide numerous ecosystem services including nutrient recycling, soil biodiversity, water storage, carbon accumulation, control of soil erosion, and weed infestation. Such agronomic and environmental benefits are achieved when 7 Mg ha^{-1} of straw (dry mater) is maintained on soil surface (about 50% of straw).

[21] Neto, M.S. et al., (2015). Direct N2O emission factors for synthetic N-fertilizer and organic residues applied on sugarcane for bioethanol production in Central-Southern Brazil. Global Change Biology – Bioenergy. Piracicaba, São Paulo – Brazil.

[22] Carvalho, J.L.N. et al. (2016). Agronomic and environmental implications of sugarcane straw removal: a major review. Global Change Biology – Bioenergy. Campinas – São Paulo, Brazil.

We should note that leaving about 40%-50% of sugarcane residues on the field leads to a mean annual C accumulation rate of 1.5 Mg ha^{-1} $year^{-1}$ for the surface to 30-cm depth (0.73 and 2.04 Mg ha^{-1} $year^{-1}$ for sandy and clay soils, respectively). It is caused by the conversion from a burnt to an unburnt sugarcane harvesting system, which is the case of the great majority of sugarcane fields in Brazil (Cerri et al, 2011).[23] Ending the practice of burning cane fields also provides additional safety benefits, which are not being captured in the mechanized credits in LCFS.

[23] Cerri, C. C., Galdos, M. V., Maia, S. M. F., Bernoux, M., Feigl, B. J., Powlson, D. and Cerri, C. E. P. European Journal of Soil Science; Special Issue: Soil Organic Matters; Volume 62, Issue 1, pages 23–28, February 2011.

Considering the above, we suggest that **up to 50% of the straw could be safely removed from sugarcane fields to produce bioelectricity without affecting GHG emissions in agricultural activities and complementing the facility's energy exports eligible for emissions credits**. We, therefore, recommend that the new calculator should have a place to input information on collected straw and its respective cogenerated electricity. This is an extremely important issue for Brazilian producers and we will be glad to collaborate with CARB to ensure that all nuances of sugarcane ethanol production are captured in the calculator.

In the latest published documents, we have noticed that staff recommended changing the N content of straw, from 0.37% to 0.53%. However, there is no clear justification for this approach apart from the "averaging" of results from four studies. UNICA does not support averaging of results, as it has no scientific basis. We would like to request that CARB staff be more specific and provide detailed information regarding the changes in this parameter so we can run accurate comparisons among the CA-GREET models. We have consulted experts who believe that actual values are closer to the lower range. We would be glad to provide further background and scientific information if we are allowed additional time. (UNICA4_SF30-4)

> **Agency Response:** Researchers at Argonne reviewed peer-reviewed literature to determine an input value for nitrogen content of above ground sugarcane biomass for the agricultural impacts from growing sugarcane. Four articles reviewed by Argonne include a range of values for nitrogen content. Currently, there does not exist extensive literature or another scientific body of evidence to corroborate the findings or conclusions from any of the articles reviewed by

Argonne. Therefore, using an average from the four studies was the most prudent approach to ensure impacts from above ground biomass are accounted in the sugarcane ethanol life cycle analysis. For responses to other issues from the commenter please see Response J-5.8 in Chapter IV.

J-5. *Simplified CI Calculator for Biodiesel and Renewable Diesel*

Comment: The Tier 1 Simplified CI Calculator for Biodiesel and Renewable Diesel states that if part of all of the co-products are used as a process fuel, co-products will not be offered.

Recommended Action: Change the above to state, "If part or all of the co-products are used as process fuel, co-product credit will not be offered for the fraction that are used as process fuel (the other fraction that is not used as process fuel should still get co-product credit)." (ECOENGINEERS3_SF22-9)

Agency Response: Please see Response J-5.3 in Chapter V.

J-6. *Simplified CI Calculator for Biomethane from Anaerobic Digestion of Organic Waste*

J-6.1. Comment: 1. Include biogenic CO2 while calculating tailpipe emissions (Cell I102 and I103) in RNG tab. Because the fuel is taking avoided methane emission credits from landfill diversion, the tailpipe emissions calculations should be similar to those in the dairy and swine manure biomethane calculator. (ECOENGINEERS_SF22-6)

Agency Response: The diversion credits offered in the biomethane derived from organic wastes pathway was for avoided fugitive methane emissions generated in the landfill, and for uncombusted methane exiting a control flare. Additionally, some avoided CH_4 and N_2O assumed to be generated when the organic wastes are composted in the baseline scenario was also credited to the pathway. CO_2 generated by tailpipe combustion of biomethane is derived from biogenic carbon; hence those emissions are excluded in the CI calculation. Please see also response J-6.6 in Chapter V regarding comparison between aforementioned calculators.

J-6.2. Comment: Provide an option for user-defined moisture content. Currently, default moisture of food waste is set at 72% and no user-defined values are currently allowed; therefore, if the actual moisture content of food waste is different from 72%, the final CI will be over or under estimated. (ECOENGINEERS_SF22-7)

Agency Response: Please see response J-6.7 in Chapter V regarding organic waste characterization and user-defined inputs.

J-6.3. Comment: Recommended Action: Please clarify how monthly weighted methane content (%) in the digester gas should be calculated for all proposed

biomethane calculators and what CARB staff will need for as supporting documents. (ECOENGINEERS3_SF22-8)

Agency Response: Please see Response J-6.8 in Chapter V.

J-7. *Simplified CI Calculator for Anaerobic Digestion of Dairy Biomethane*

J-7.1. Comment: The data in Table A.4. in the References Tables for the Livestock GREET Tool is pretty out of date. The EPA typically release updated defaults every year in April in their annual GHG Inventory. Their latest release is here: https://www.epa.gov/sites/production/files/2018-01/documents/2018_annex_3_-_part_b. (see Table A-185) - you will need to convert to kg/day/1000kg of animal mass. Seems they have changed these updates to every two years with the next one due to come out in April 2019. Wanted to pass on to see if you could update these given that the GREET Tool may not be updated until the early 2020s by which time the defaults might be 10 years out of date. (CIG1_SF2-1)

Agency Response: The 2012 reference year data was used in Table A.4 because it is in line with the CARB-approved Compliance Offset Protocol Livestock Projects (Livestock Protocol), which provides a robust quantification framework for avoided methane from livestock projects. Staff believes that the LCFS requirements and methodology for calculating the Baseline methane emissions should be consistent with those in the Livestock Protocol.

J-7.2. Comment: DTEBE has requested that CARB consider making changes to the Tier 1 dairy biomethane calculator to allow for the calculation of carbon emissions from the trucking of dairy biomethane from an upgrading facility to a centralized interconnection point. Trucking processed gas to a centralized interconnection site allows for broader development of dairy biomethane projects and allows developers to better access the interstate gas system. Trucking processed RNG is quickly becoming the industry standard for biomethane projects. <u>DTEBE has provided requested information to CARB on the emissions resulting from trucking RNG for our projects in development. We request that CARB make this addition to the calculator during this current rulemaking cycle</u>. Adding this ability to the Tier 1 pathway calculator for dairy biomethane will better reflect industry practices and help speed the registration and verification process for new dairy biomethane projects that hope to participate in the LCFS program. This change will provide benefits for developers hoping to utilize the Tier 1 pathway and help conserve CARB staff resources by preventing these projects from undertaking the Tier 2 pathway process because of the common practice of trucking processed biomethane from a dairy farm. (DTEBE3_SF19-4)

Agency Response: Staff appreciates information provided by the commenter. The Tier 1 pathway Calculator is designed to include pathway elements (i.e., transport of finished fuel) for which staff has extensive experience evaluating since the inception of the program. Transport of renewable natural gas by truck has not been considered, since this mode was never utilized or requested by stakeholders previously in the program. Pathway applicants may request the

inclusion of this option through a Tier 2 pathway, subject to substantiality requirements.

J-7.3. Comment: There are numerous dairies that utilize diluted wash down effluent, which is then screened for solids prior to discharge to the lagoon. The solids are utilized for nutrition management.

However, there is a sizeable decrease in VS in the effluent due to the screening, which underreports the CH4 emissions in the baseline.

We are proposing COD, a known substitute currently used by IPCC to determine emissions. It is insensitive to screening procedures and would provide an accurate assessment of the baseline and project performance in BCS systems that process diluted effluent. (TRANE1_SF38-1)

Agency Response: The COD approach as suggested by the commenter is not relevant for use in the LCFS program. In the Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure, applicants are required to define the fraction of volatile solids (VS) sent to anaerobic storage/treatment system, which represents the percent of manure and excludes any VS removed by solid separation equipment from the calculation. Site-specific data must be used if available; otherwise, the calculator provides reference values for different solid separation methods. Therefore, the liquid/solid separation process is already taken into account in the calculator, and the VS will not be impacted by the dilution of the manure as it is measured on a dry-weight basis. Additionally, since the baseline methane emission is a modeled theoretical value and it has significant impact on the total avoided emission credit, staff believes using VS as the measurement of maximum CH_4 potential will treat all relevant applications equitably. Furthermore, the VS-based measurement in the Tier 1 Simplified CI Calculator is consistent with the methods used in CARB's Compliance Offset Protocol Livestock Projects (LOP), the IPCC guidance (2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 4, Chapter 10), and the U.S. EPA Code of Federal Regulations (Title 40, Part 98, Subpart JJ).

J-8. *Simplified CI Calculator for Biomethane from Anaerobic Digestion of Wastewater Sludge*

J-8.1. Comment: *1*. Section 95488.3(b) – References the simplified calculator for Tier 1 fuels. The calculator for wastewater plants assumes 100% grid based natural gas is utilized to convert the biogas into low carbon transportation fuel. In many instances, we expect biogas-based power to be utilized for this purpose. There should be a means to enter site specific data into the calculator to override this assumption. (CASA3_SF39-2)

Agency Response: The baseline case for wastewater biomethane is flaring of biogas. Therefore, any biogas used as process fuel does not have to be

accounted in the Simplified CI Calculator. However, if any fossil inputs (i.e, natural gas, grid electricity) are utilized in the operation of the wastewater facility, such inputs need to be accounted in the Calculator.

J-8.2. Comment: *4*. Section 95488.9(f)(2) States that: "A fuel pathway that utilizes an organic material may be certified with a CI that reflects the reduction of greenhouse gas emissions achieved by the voluntary diversion from decomposition in a landfill and the associated fugitive methane emissions, provided that:

a. (A) The organic material that is used as a feedstock would otherwise have been disposed of by landfilling, and the diversion is additional to any legal requirement for the diversion of organics from landfill disposal."

This raises questions regarding the implementation of SB 1383 and the use of sewage sludge biogas. Sludge is first digested, producing biogas and biosolids. The biosolids then may be used in a variety of ways (land application, compost production, or landfill use as alternative daily cover). We assume all sludge being digested is considered to be voluntarily diverted from landfilling for the purposes of this section but please confirm. Similarly, the biogas may also be used in a variety of ways (electricity production, heating via boilers, pipeline injection, low carbon transportation fuel, etc.). We assume the choice to produce low carbon transportation fuel is taken voluntarily to comply with this section, but please confirm. (CASA3_SF39-5)

Agency Response: Please see Response J-8.1 in Chapter V.

J-8.3. Comment: *5*. The simplified calculator incorporated by reference for wastewater sludge contains multiple assumptions which we question. For example, the calculator assumes a 1% slip (loss) of methane from an anaerobic digestion system. What is the justification for such an assumption since that assumes a worse-case scenario and would not be seen in typical applications? We are still working through other nuances of the calculators but have grave concerns since the CI's appear to be far higher than the established pathways currently in regulation. This is in contradiction to the opinions staff articulated when introducing the concept of the calculator when it was argued that conservative assumptions were utilized in developing the pathways. When using the calculator for specific projects it was expected that lower CI's would result. We request additional time to evaluate the assumptions built in to the calculator, or modifications to it which better reflect real world experience using California wastewater treatment plants. (CASA3_SF39-6)

Agency Response: Please see Response J-8.2 in Chapter V.

J-8.4. Comment: We welcome the opportunity to discuss this further and to provide any additional information or clarification on any of our points. We have truly appreciated the efforts made by your staff and believe the wastewater sector is a desired participant in the program. (CASA3_SF39-7)

Agency Response: We thank the Commenter for their input and support.

J-8.5. Comment: *2.* Section 95488.3(c)(1) – Provides an exception to use multiple carbon intensities when utilizing multiple feedstocks. Is this intended to account for co-digestion at wastewater treatment plants when accepting food and other organic waste which would otherwise be landfilled? Some wastewater plants accept a variety of waste streams for anaerobic digestion and conversion into renewable energy. In these cases, this exception would introduce a technical and administrative complexity that may discourage facilities from participating in the program and achieving the objectives of SB 1383. Wastewater plants already receive significant food waste via garbage disposals and the sewerage system and should not be penalized simply for introducing it directly into the digester. The wastewater sector is expected to be a key partner with the state by utilizing our excess digester capacity to accept organic waste diverted from landfills. Markets must be assured for this biogas and the LCFS credits are critical for these projects to be economically viable. The requirements to measure, calculate, and establish CIs for individual waste streams for facilities with a diverse set of feedstocks will discourage them from participating in the LCFS program. (CASA3_SF39-3)

> **Agency Response:** In the LCFS program, life cycle treatment of feedstocks used in biomethane pathways is quite varied. Some include avoided methane credits while some do not include this credit. It is, therefore, quite likely that the applicant shall benefit by the use of feedstock-specific carbon intensities (CI). If the applicant prefers to have the option for a single CI, a conservative approach would be to exclude methane avoided credits for all feedstocks used in biomethane production.

J-9. *Book-and-Claim Accounting of Biomethane*

Comment: In the Second Notice of Public Availability of Modified Text, Section N (page 19), the following statement is made regarding § 95488.8(i)(1) and § 95488.8(i)(2):

N. Modifications to Section 95488.8. Fuel Pathway Application Requirements Applying to all Classifications.

   1. In section 95488.8(i)(1) and (2), staff proposes to clarify that book-and-claim accounting may be used for electricity and biomethane supplied to produce hydrogen that is used as a transportation fuel, as well as hydrogen used in the production of a transportation fuel—including both hydrogen used in petroleum refineries, which can be claimed under the Renewable Hydrogen Refinery Credit provision, and hydrogen used e.g., in hydrotreatment for renewable diesel production.

WSPA requests that CARB verify that such processes as hydrocracking and renewable gasoline would be included in the list along with renewable diesel production. As CARB's explanation above is intended as an example and not an exhaustive list, perhaps adding "e.g., <u>but not limited to</u> hydrotreatment for renewable diesel production" or add "and hydrocracking for gasoline". (WSPA7_SF29-1)

Agency Response: Staff affirms that hydrocracking and renewable gasoline will be covered by the above mentioned section. The "e.g., in hydrotreatment for renewable diesel production" in the cited statement is only intended as an example and not an exhaustive list.

J-10. *Temporary Fuel Pathways*

J-10.1 Comment: Section §95488.9(b)(4) creates uncertainty for producers whose fuel pathways are not listed in Table 8 because these producers have the potential to lose substantial revenue for up to 2 calendar quarters while they create and submit their full pathway application. It is essential to have a clear Temporary Pathway application process for new feedstock-fuel combinations to apply to CARB for consideration.

Recommended Actions:

1. Provide a process for producers to create a new temporary pathway and CI to be added to Table 8. Also, provide a process for an entity to create a new temporary CI value for a temporary pathway that is currently listed in Table 8. (ECOENGINEERS3_SF22-1)

Agency Response: Please see Response J-10.4 in Chapter V.

J-10.2. Comment: It seems premature and unnecessary to eliminate previously adopted pathways and assign them higher carbon intensity (CI) values that appear arbitrary. We highly recommend retaining the original pathways and CI values until project specific values are developed. This is especially true for transportation fuel derived from wastewater biogas for which there is a proposed six-fold increase in the CI for large wastewater treatment plants. (CASA3_SF39-1)

Agency Response: Please see Response J-10.5 in Chapter V.

J-10.3. Comment: *3.* Section 95488.9(b)(4) Table 8 – Temporary Pathways for Fuels with Indeterminate CI. This table provides a temporary CI value of 45 g CO_2e/MJ for CNG derived from wastewater sludge biogas. We have not found an explanation for this change and it appears unfounded, as well as unnecessary. It is almost a six-fold increase from the established pathway for large wastewater treatment plants and a 50% increase for small plants. We strongly recommend the retention of the existing pathways as noted in our general comment above. (CASA3_SF39-4)

Agency Response: Please see Response J-10.3 in Chapter IV. Additionally, please see Response J-10.5 in Chapter V.

J-11. *Co-Processing*

J-11.1. Comment: REG looks forward to updating of all ours fuel pathways under the new simplified Tier 1 model. We encourage staff to allow reapplications to begin at the start of 2019. We believe that a longer lead time will avoid the workload issues faced by

companies and CARB staff alike which resulted from the rush of new pathways in 2016 which stemmed from re-adoption. (REG4_SF65-7)

> **Agency Response:** Please see Response J-2.16b in Chapter V regarding the timeline for the new pathway application certification in 2019.

J-11.2. Comment: We understand CARB's desire to continue with designing a framework for co-processing, we recognize that co-processing is fundamental to CARB's fuel neutral approach and we appreciate that CARB is holding a workshop on this issue. We believe that a new, separate rulemaking is required before any new pathways can be approved. While it has been CARB's position that co-processing is a Tier 2 application, we disagree for several reasons. First, the current GREET 3.0 model does not support a framework for the evaluation of these pathways. Any effort to 'build out' GREET 3.0 to accommodate these pathways need to be subject to public review. It is our understanding that the model cannot be fundamentally changed without a public review. We encourage CARB to build a co-processing specific calculator which is incorporated into the regulation. Much thought and discussion needs to be had about how to calculate incremental energy demand related to co-processing, what is considered an appropriate baseline, how to account for adjustments in crude slate, and product yields. These are fundamental questions which will have significant impacts on these pathways. CARB ought to have specific, clear rules on these questions. They are beyond the realm of a guidance document or protocol and should be included in the regulation, similar to carbon capture and sequestration or the refinery investment and credit pilot program.

We believe that without a separate, public process to develop a co-processing framework, refineries will submit heavily redacted life cycle reports and life cycle models which will be so redacted as to yield public scrutiny impossible. REG has submitted several Tier 2 pathways, one of which received public comments. We welcomed these comments as sign that stakeholders care about the integrity of the program. (REG4_SF65-8)

> **Agency Response:** Please see Response J-11.1 in Chapter V in relation to certification process for co-processing applications.

J-11.3. Comment: REG is also concerned that CARB will be encouraged by co-processors to validate the production of renewable gallons using a mass balancing method. This is unacceptable, no matter the feedstock or process utilized. As REG, NBB, and the Joint Research Center (JRC) can demonstrate, ^{14}C radio carbon assay, whether conducted using method B or C of ASTM D6866 is extremely accurate and affordable. (REG4_SF65-9)

> **Agency Response:** Please see Response J-11.2. in Chapter V.

J-11.4. Comment: *Refinery Hydrogen Program*

REG supports the change to this program to allow opportunities for stand-alone renewable diesel plants. We believe this change is consistent with the spirit of the

regulation and allows for competition for biomethane within the marketplace. CARB should consider how verification of this program may function as many facilities share common utilities when located within a chemical park. For example, it is not uncommon for several facilities to share a single steam methane reforming system that supplies hydrogen to several facilities. We believe that a joint application per the new guidelines in the updated regulation would be an appropriate mechanism to accommodate for insuring the correct about of biomethane is purchased to cover the hydrogen utilized by the facility. (REG4_SF65-10)

> **Agency Response:** A renewable diesel facility using biomethane as feedstock for renewable hydrogen production can capture benefits associated with this biomethane use through Tier 2 applications. In a case where the same renewable hydrogen is shared among several facilities, the hydrogen production facility can either provide metered data for feedstock and hydrogen production to the renewable diesel production facility or opt-in to become a co-applicant, thereby enabling it to provide data to ARB directly. Verification requirements would be the same as applicable to other fuel pathways. Metered data and documentation supporting upstream sourcing of biomethane should be made available to a third-party auditor as part of mandatory verifications requirements in the regulation.

J-12. Multiple Comments: *Indirect Land Use Change*

Comment: As we have urged in the past, CARB should also incorporate the latest indirect land use change values from the GTAP model into GREET. (*Id.*) (GROWTHENERGY3_SF31-2b)

Comment: In its second 15-Day Modifications, CARB did not address our comments on CARB's First 15-Day Notice, submitted on behalf of Growth Energy, on utilizing a more recent version of the GTAP model. The LCFS should be modified to address each of these concerns. (GROWTHENERGY3_SF31-7)

Comment: In addition, as I have indicated in previous comments, CARB should revise estimates of emissions related to indirect land-use changes using the latest version of GTAP. (GROWTHENERGY3_SF31-13)

> **Agency Response:** Please see Response J-14.2 in Chapter IV to address the comments above related to indirect land use change.

J-13. *Book-and-Claim Accounting/Renewable Determination*

Comment: Renewable Power Usage in Production, Distribution, and Dispensing: Electrical power is an important input in all aspects of hydrogen production, compression, liquefaction, distribution, and dispensing. Electricity is the primary input when hydrogen is produced by electrolysis from water, but electrical power is also a significant source of energy for compression, liquefaction, pumping, and refrigeration of

hydrogen produced by any method. Therefore, it is important that the LCFS regulations recognize renewable electricity as such whenever it is used in a hydrogen pathway.

For example, in proposed Sections 95481, 95486, and 95488, the credits available for improvements in the CI of electricity used for the production of hydrogen by electrolysis should also be available for improvements in the CI of electricity used for compression, liquefaction, distribution or dispensing.[1]

[1] **Section 95481.(a)(124)** "Renewable Hydrogen" means hydrogen derived from (1) electrolysis of water or aqueous solutions using renewable electricity; (2) catalytic cracking or steam methane reforming of biomethane; or (3) thermochemical conversion of biomass, including the organic portion of municipal solid waste (MSW). Renewable electricity, for the purpose of renewable hydrogen production by electrolysis ***or for hydrogen compression, liquefaction, distribution or dispensing,*** means electricity derived from biomass, including the organic portion of MSW, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, electricity generated from a small hydroelectric facility of 30 megawatts or less, biogas, ocean wave, ocean thermal, and tidal current.

(H2IND3_SF6-4a, H2IND4_SF7-4a)

Agency Response: Please see Response J-13 in Chapter IV.

K. Crude Oil and Innovative Crude Production Method Provisions

K-1. *Innovative Crude Production Method*

K.1.1. *Book-and-Claim Accounting for Electricity and RNG*

Comment: In new § 95489(c)(1)(A)(5), CARB has elected to not permit book and claim for Renewable Natural Gas (RNG) usage for transportation facilities which have been added under this section. Book and claim is an essential tool for matching RNG supply with demand because the projects are frequently located in different geographical areas.

Similarly, the proposed regulatory language requires solar electricity be supplied directly to transport facilities (and oil and gas fields) and not through indirect accounting. This language is too limiting as implementation requirements for solar often do not coincide with oil production.

For each of these direct-supply situations, WSPA encourages CARB to at least incorporate a distance limit requirement such as broadening it to include only RNG or solar electricity produced in California. WSPA views the requirement for direct physical supply of RNG and solar energy to crude transport and oil production facilities as a missed opportunity to provide an appropriate incentive to develop this area of the program. WSPA encourages CARB to re-evaluate their position and allow book and claim for RNG and solar energy under § 95489. (WSPA7_SF29-10)

> **Agency Response:** Please see Response in K-3.6, Book-and-Claim Accounting for Solar and Wind Electricity, in Chapter IV and Response K-3.2, Book-and-Claim Accounting for RNG, in Chapter V.

K.1.2. *Energy Sources Removed from the Innovative Crude Provisions*

Comment: As revised, § 95489(c)(1)(A)(5) has removed the following energy sources from the innovative crude provisions: geothermal, ocean wave, ocean thermal, or tidal current energy generation. WSPA strongly encourages CARB to reinsert these carbon free energy sources as they would demonstrate CARB's commitment to an all-of-the-above energy portfolio without prejudice as to the source or destination of carbon free energy. (WSPA7_SF29-11)

> **Agency Response:** Staff will continue to consider the use of such energy sources in crude applications.

L. Refinery-Related Provisions

L-1. Multiple Comments: *Support for the Modifications to the Renewable Hydrogen Refinery Credit Program*

Comment: The proposed changes that relate to renewable hydrogen refinery credit program will create policy certainty and enable the use of renewable hydrogen credits within California refineries

Iogen supports the suggested changes around renewable hydrogen refinery credit program in the draft regulatory text. CARB has proposed changes that will create policy certainty and enable renewable hydrogen usage within California refineries, which include:

- Removing the term "pilot" in the title of the program
- Removing the requirement that RHC must replace a minimum 1% of fossil hydrogen
- Removing the requirement that RHC will generate a maximum of 10% of annual compliance obligations
- Removing a limit that credits created may not be sold or transferred to any another party

Iogen also supports the proposed changes that relate to the calculation of credits for the renewable hydrogen refinery credit program. The credit calculation definition now appropriately includes the biogenic credit for the renewable natural gas (RNG) usage, which will offer a level playing field between the use of RNG for the production of either CNG or the renewable hydrogen refinery credit program. (IOGEN2_SF23-1)

Comment: We appreciate CARB's commitment to improving the LCFS program and enabling a diverse set of solutions for credit generation. We look forward to advancing the renewable hydrogen refinery credit program in California. (IOGEN2_SF23-3)

> **Agency Response:** Staff appreciates the commenter's support of changes to the Renewable Hydrogen Refinery Credit Program.

L-2. *Refinery Investment Credit Program*

L-2.1 *Preliminary Estimate of the Refinery Investment Credit*

Comment: WSPA continues to look forward to the potential of the Refinery Investment Credit Program (RICP) as revised in 94589(e), and appreciates the removal of the word "Pilot" from its name. There is one element, however, that needs to be clarified. The program as outlined in 95489(e) contemplates the need for application for credits well in advance of the project being implemented. Indeed, language proposed in 95489(e)(3)(A)3 specifically references a "*preliminary* estimate of the refinery investment credit" (emphasis added). This early understanding of credit generation

potential for a project is important, and given CARB's desire that this program would incent projects to reduce GHG emissions and carbon intensity of fuels that would not otherwise be justified, it is logical that applicants would need this understanding to progress their investment decisions. (WSPA7_SF29-12)

> **Agency Response:** The preliminary estimate of refinery credits (as proposed in section 95489(e)(3)(A)3) will allow staff to assess the likely magnitude of each project. Note that credits are awarded only after the project becomes operational and data/calculations are verified. To facilitate the application process, applicants are encouraged to contact staff early in the process to develop a good understanding of the proposed refinery project, its system boundary and steps involved in calculating credits.

L-2.2 *Timing of Approval and Implementation of a Project*

Comment: Even after a final investment decision is taken with the benefit of this understanding, there will be significant gap of time from approval to implementation of the project and its actual generation of credits. For large projects, this could be many years and dependent on the timing for receipt of final permits, procurement and installation of equipment and the time to successfully start-up the unit and prove its benefits. Given the need for investment certainty, WSPA recommends amending language in the current 15-day edits as follows in section 94589(e)(1)(G)3:

> *"3. Crediting is limited to 15 years from the quarter in which the ~~Executive Officer approves the project's application~~first qualified verification statement for the project is received, as per the requirements of 94589(e)(3)(A)."* (WSPA7_SF29-13)

> **Agency response:** Staff disagrees with the recommended change to the start of crediting period from the date of application approval to the date of the first qualified verification statement. Staff's intent for starting the 15-year crediting period on the date of application approval is to provide incentive for entities to bring their projects online as soon as possible to maximize credit generation within the crediting period. This timing helps to ensure that only serious applications that are ready to be implemented will be submitted for approval and staff review.

L-3. *Renewable Hydrogen Refinery Credit Program*

Comment: § 95489(f)(2)(A) contains the calculation methodology for determining credits from renewable hydrogen produced from renewable natural gas (RNG). While staff has proposed a change referencing the CI of fossil natural gas (NG) and RNG from "refinery gate" to "well-to-hydrogen," this does not make it clear that the biogenic carbon released from the RNG-to-hydrogen production process should be credited to the renewable hydrogen. To eliminate uncertainty in the regulatory language, WSPA recommends amending the language to specifically reference the biogenic carbon credit associated with RNG-to-hydrogen production. Alternatively, the credit value could be added to the credit calculation formula. (WSPA7_SF29-14)

Agency Response: The term “well-to-hydrogen” is intended to capture all credits and emissions from well-to-hydrogen production including combustion and non-combustion GHG emissions at the hydrogen production unit. It is intended to be inclusive of RNG-to-hydrogen. As a result, any credits/benefits associated with biogenic carbon would also be accounted for. There is no need to specifically reference the biogenic carbon credit associated with RNG-to-hydrogen production.

L-4. *Credit Generation at Refineries*

Comment: Staff have proposed a number of provisions which allow refineries to reduce on-site emissions resulting from the production of transportation fuels, subject to certain limits and conditions. We agree that such projects deserve recognition and LCFS credits for the real, quantifiable, additional and verifiable emissions reductions they produce. We support the use of facility-level analysis rather than process-level, in order to ensure that improvements which receive credits do not increase emissions at other parts of the refinery, outside the analyzed system boundaries in the LCFS credit pathway. We are concerned that the current proposal may allow refineries to claim credit for upgrades which were required by law or regulation other than the LCFS. We urge CARB to interpret the term “baseline” in § 95489 (e) (1) (D) (5) to include projects, retrofits or upgrades required for compliance with appropriate law or regulation in the refinery’s jurisdiction. (NEXTGEN4_SF60-15)

Agency Response: Please see Response L-2.8 in Chapter V.

M. Carbon Capture and Sequestration

M-1. Multiple Comments: *Support for the Proposed Carbon Capture and Sequestration Provisions*

M-1.1 Multiple Comments: *Support for CCS Protocol*

Comment: Thank you for the opportunity to comment on the proposed amendments to the LCFS regulation and to the regulation on commercialization of alternative diesel fuels. In particular, NSP is pleased with ARB's modifications to the CCS protocol, the inclusion of grain sorghum fiber as a cellulosic feedstock and the change in the sorghum farming input data underlying CA-GREET 3.0. (NSP1_SF15-1)

Comment: As proposed, the CCS pathway will enable ethanol plants to become carbon neutral or even carbon sinks. A biological process used to produce energy—like that employed in ethanol plants—has a significant positive impact on carbon sequestration as it actually removes carbon from the atmosphere. Contrast this with CCS associated with fossil fuel production, which sequesters methane that had already been sequestered, and couple that with added food production, and the benefits of ethanol on the carbon cycle are clear. (NSP1_SF15-2)

Comment: White Energy would like to state its support for the inclusion of the Carbon Capture Protocol and applaud CARB staff on intense effort that was taken to push this protocol to completion. The finished product is robust and polished with a few final suggested improvements below. (WE4_SF20-1)

Comment: Occidental values and supports CARB's leadership role in developing amendments to the LCFS and developing a protocol for carbon capture and sequestration. CARB staff has been active and engaged in working with stakeholders to craft language that will ensure that GHG reductions from CCS are real, permanent, quantifiable, verifiable, and enforceable. The LCFS revisions and Protocol will appropriately incentivize involvement and aid California in its pursuit of mid-century climate goals. (OCCIDENTAL5_SF21-1)

Comment: WSPA appreciates the progress that CARB staff has made on the CCSP, as presented in the 2nd 15-day Modifications. As we have stated in previous comment letters, the CCSP is an important guidance document by which successful projects could be permitted and constructed. (WSPA8_SF33-1)

Comment: WSPA appreciates the progress that CARB staff has made on the CCSP, as presented in the 2nd 15-day Modifications. As we have stated in previous comment letters, the CCSP is an important guidance document by which successful projects could be permitted and constructed. (WSPA9_SF34-1)

Comment: DTEER appreciates the work done by CARB in advancing CCS as means of reducing California's carbon intensity. (DTEER1_SF36-1)

Comment: We appreciate the opportunity to share our thoughts on the CCS Protocol. (DTEER1_SF36-6)

Comment: We believe CCS can be a key component of California's strategy to reduce carbon emissions. DTEER further believes acceptance of the changes described above will help move CCS projects forward in a manner this is safe and protective of the environment. (DTEER1_SF36-7)

Comment: We commend ARB for making some important improvements to the Protocol in the 15-day Modifications released Aug. 13, 2018, following the 15-day comment period on the June 20, 2018 15-day Modifications. We believe that these strengthen the Protocol and afford a greater degree of oversight and environmental protection. We point out a few modifications that require further consideration or edits below. (CATFNRDC2_SF40-1)

Comment: We support the recent changes to the definition of "plume stabilization," which allow for predictive deterministic approaches to assess the risk of leakage in a 100-year timeframe. (CATFNRDC2_SF40-2)

Comment: C.1.1.3.2

We support ARB's modification providing a choice between quarterly and annual reporting, which allows for consistency with US EPA's Greenhouse Gas Reporting Program Subpart RR requirements (at 40 C.F.R. § 98 Subpart RR). Streamlining these requirements will allow operators to more efficiently compile and submit required operational and emissions data to ARB and USEPA. (CATFNRDC2_SF40-8)

Comment: C.2.3.1(d)

We support the proposed language that would allow historical data to be submitted in lieu of the data required in the preceding subsections. In some EOR storage projects, for example, where long operating histories have led to the accumulation of detailed data and records characterizing the subsurface geology including confining sequences and reservoirs as well as other useful metrics such as injectivity and production, this could yield superior quality data. (CATFNRDC2_SF40-10)

Comment: C.2.3.1(f)

We support ARB's change from the terminology "confining layer" to "primary confining layer". (CATFNRDC2_SF40-11)

Comment: Macpherson Energy Corporation (Macpherson) appreciates the efforts and time CARB and its consultants have put into the development of the proposed Carbon Capture and Sequestration (CCS) Program. The benefit of a CCS program is that it removes CO_2 from the environment thereby reducing California's CI. Macpherson's comments support a scientific approach to reducing California's Carbon Intensity (CI) by applying set standards and engineering practices to ensure safe CCS.

Macpherson recognizes that approving a CCS site requires multiple phases with numerous California and Federal governmental agencies, and engagement with the citizens of California. With this level of oversight a set regulatory path, based on science, must be implemented. Without a working regulatory process the developing and implementing a successful CCS project would be impossible. (MACPHERSON1_SF48-1)

Comment: Carbon Capture and Sequestration (CCS) is a rapidly-developing technology that has demonstrated significant potential, in a limited number of pilot projects, for reducing GHG emissions. Almost every global emissions scenario which prevents catastrophic levels of climate change includes significant deployment of CCS. CARB once again finds itself as the global leader in climate policy by crafting provisions under which the emissions reductions from CCS are recognized and assigned financial value by a carbon market. It is absolutely critical that CARB strike the right balance between encouraging the deployment of CCS projects and ensuring that they provide real, permanent sequestration. With only a few exceptions, we support the current proposals on CCS and commend staff for producing a framework which should support the deployment and regulation of CCS projects within the California fuels market. (NEXTGEN4_SF60-16)

> **Agency Response:** Staff appreciates the support for the CCS Protocol as a whole, as well as the changes that were made to the Protocol in response to the comments submitted during the first 15-day comment period. Staff appreciates the support for specific revisions to the Protocol (see, for example, comments CATFNRDC2_SF40-2 and CATFNRDC2_SF40-10).

M-2. Multiple Comments: *Definitions*

M-2.1 *Definition Storage Complex and System Boundary*

Comment: The Carbon Capture and Sequestration Protocol (CCS Protocol) has made definitional changes in the latest versions that now defines the area in which the storage is taking place as the "storage complex", however in defining the system boundary the terms "Sources, sinks and reservoirs (SSRs)" is used to describe the project in total. The term reservoir in a geologic sense can be described as "a place where fluid collects, especially in rock strata…" and in oil and gas refers to where "the subsurface pool of hydrocarbons contained in porous or fractured rock formations." These formations can be described as fields and these fields can be subdivided into individual wells or units (a grouping of wells). In both cases the reservoir can be a very large area covering several hundred miles. By describing the system boundaries using the term "reservoir" instead of "storage complex" a misinterpretation can be made that "storage complex" and "reservoir" are interchangeable terms. In the case of a sequestration project a saline aquifer that would be utilized for storage could be incredibly large. The Illinois Carbon Capture and Storage project (ICCS) utilized the 200 acres while the Illinois Basin in which the saline aquifer exists is orders of magnitude larger than that. When looking at EOR (Enhanced Oil Recovery), the subdivided reservoir is not delineated necessarily by geologic subsurface formations and no single owner typically

has 100% ownership or operation of an oil reservoir. Both of these examples highlights the need for clarification on the term "reservoir" in the system boundary definition. CARB staff in the protocol later describes how plume modelling can help define the storage complex for the purpose of guaranteeing 100 years of permanence. It is therefore urgent that CARB issue clarification or corrective language to avoid confusion as to how the system boundary will be defined. (WE4_SF20-2)

> **Agency Response:** Staff does not agree with the commenter's assertion that the system boundary is confused by its use, or the use of "storage complex," in the Protocol. This system boundary is defined in subsection B.1 of the Protocol, and is used exclusively within the Accounting Requirements in the context of issuing credits based on injected CO_2. The "storage complex" term is used to define the storage volume <u>and the confining system</u> within the Permanence Requirements. Therefore, staff made no modifications to the Protocol in response to this comment.

M-2.2 Multiple Comments: *Definition and Use of "AOR"*

Comment: It appears that the definition of Area of Review (AoR) has been removed in favor of "storage complex". However, there remain numerous references to the term "AoR" in the document. As there is a clear distinction between the storage complex (the 3-D space in the subsurface) and AoR (the 2-D projection onto the surface), the document does need further editing to add back the definition of AoR and also to ensure the consistent and accurate application of these terms. (WSPA8_SF33-4)

Comment: It appears that the definition of Area of Review (AoR) has been removed in favor of "storage complex". However, there remain numerous references to the term "AoR" in the document. As there is a clear distinction between the storage complex (the 3-D space in the subsurface) and AoR (the 2-D projection onto the surface), the document does need further editing to add back the definition of AoR and also to ensure the consistent and accurate application of these terms. (WSPA9_SF34-4)

Comment: In many places within the CCS Protocol, "AOR" has been replaced by "storage complex" or "surface projection of storage complex". However, in other areas, "AOR" is still used, but is no longer defined. DTEER recommends the following changes in the Definitions section: (DTEER1_SF36-3)

A. Remove part (A) of the definition of Storage Complex in its entirety, and replace with the following (note: part (B) to remain unchanged):

   (A) "The storage complex includes the injection zone (in which the CO_2 is emplaced), a sequestration volume, which is expected to contain the CO_2, and overlying and possibly underlying geologic formations that are required to provide assurance of storage. The storage complex must include a multilayered confining system that retards vertical migration of CO_2. The storage complex must extend laterally over (1) the volume from which CO_2 (as a free or dissolved

phase) could escape from storage in the subsurface if a permeable pathway exists, and (2) the area over which the plume may migrate."

B. Add a new definition for AOR (which is used within the document but is no longer defined) as follows:

"Area of review (AOR)" means the area encompassing the lateral extent and depth of the storage complex. (DTEER1_SF36-4)

Comment: Various: replace "AoR" with "Storage Complex"

For consistency with the elimination of the term "Area of Review" in the document, there are several remaining locations in the document where "AoR" should be replaced with "storage complex." Please see the following locations: p. 55 C.2.3(a)8(D), C.2.3(a)8(E); p. 56 C.2.3(c)(2); p. 64 C.2.4(b)(1)(C); p. 70 C.2.4.3(a)(1)(A), C.2.4.3(a)(1)(B); p. 71 C.2.4.3(b)(1), C.2.4.3(b)(2), C.2.4.3(c); p. 73 C.2.4.3(d), C.2.4.3(e)(1); p. 80 C.2.5(c)(3); p. 130 C.7(d);and p. 135 C.9(b). (CATFNRDC2_SF40-17)

Comment: In many places "AOR" has been replaced by "storage complex" or "surface projection of storage complex". However, "AOR" is still used in the document, but is no longer defined.

Recommendations to Definitions:

Definition of Storage Complex:

"Storage Complex" means the three-dimensional subsurface volume that is characterized, modified by corrective actions, and monitored so sequestration under the Permanence Requirements (section C).

(A) "The storage complex includes the injection zone (in which the CO_2 is emplaced), a sequestration volume, which is expected to contain the CO_2, and overlying and possibly underlying geologic formations that are required to provide assurance of storage. The storage complex must include a multi layered confining system that retards vertical migration of CO_2. The storage complex must extend laterally over (1) the volume from which CO_2 (as a free or dissolved phase) could escape from storage in the subsurface if a permeable pathway exists, and (2) the area over which the plume may migrate."

Add a definition for AOR: AOR is used within the document but is no longer defined. "Area of review (AOR)" means the area encompassing the lateral extent and depth of the storage complex. (CIPA3_SF46-2)

Comment: In many places "AOR" has been replaced by "storage complex" or "surface projection of the storage complex". However, "AOR" is still used in the document, but is no longer defined. Macpherson's recommendations are to redefine Storage complex to be consistent with the changes recommended above for A(1) Applicability, and add a definition for AOR.

"Storage Complex" means the three-dimensional subsurface volume that is characterized, modified by corrective actions, and monitored so sequestration under the Permanence Requirements (section C).

(A) "The storage complex includes the injection zone (in which the CO_2 is emplaced), a sequestration volume, which is expected to contain the CO_2, and overlying and possibly underlying geologic formations that are required to provide assurance of storage. The storage complex must include a multi layered confining system that retards vertical migration of CO_2. The storage complex must extend laterally over (1) the volume from which CO_2 (as a free or dissolved phase) could escape from storage in the subsurface if a permeable pathway exists, and (2) the area over which the plume may migrate."

Add a definition for AOR:

"Area of review (AOR)" means the area encompassing the lateral extent of the storage complex. (MACPHERSON1_SF48-3)

Agency Response: The commenter correctly identifies that the term "AOR" is no longer defined, and that most occurrences of the term have been replaced consistent with the modification explained in the notice. As indicated in that notice, all occurrences of the term "AOR" were intended to be replaced with "surface projection of storage complex" throughout the Protocol. As indicated in this FSOR, these non-substantial corrections have been made to the final version of the protocol.

M-2.3 ***Definition of Plume Stability***

Comment: However, the terms "small" and "predictable" are subjective and not precisely defined. In addition, the definition should be focused on atmospheric leakage, not migration, out of a defined storage complex.

We recommend the following changes:

"[...] pressure changes are <u>sufficiently</u> small and predictable, such that the measured rate of plume migration has a high certainty of no <u>atmospheric</u> CO_2 leakage over a 100-year period." (CATFNRDC2_SF40-3)

Agency Response: See Response M-2.3 in Chapter V.

M-2.4 ***Definition of Storage Complex***

Comment: <u>A.2(a)(107)(A)(2)</u>

We recommend that ARB revise the definition of "storage complex" at (2) to read:

"The storage complex must encompass the volume within which the plume is predicted to migrate." (CATFNRDC2_SF40-4)

Agency Response: See Response M-2.3 in Chapter V.

M-2.5 ***Definition of Completion Interval***

Comment: In Section C.2.5(b)(2)(28), WSPA suggests that the definition of "Completion interval" be revised to replace "channels" with "pathways for flow" to reflect the possible use of sand screens, slotted liners or even open hole completions, none of which imply existence of channels. (WSPA8_SF33-8a)

Comment: In Section C.2.5(b)(2)(28), WSPA suggests that the definition of "Completion interval" be revised to replace "channels" with "pathways for flow" to reflect the possible use of sand screens, slotted liners or even open hole completions, none of which imply existence of channels. (WSPA9_SF34-8a)

Agency Response: Staff did not modify the protocol in response to this comment as there are no other provisions that bar an operator from using sand screens, slotted liners, or open-hole completions, provided these methods are approved by the Executive Officer.

M-3. Multiple Comments: ***Applicability***

Comment: CCS Protocol, Section A(1). Applicability.

DTEER proposes to remove the current language in this section and replace it with the following:

"The Carbon Capture and Sequestration (CCS) Protocol applies to CCS projects that capture carbon dioxide (CO_2) and sequester it onshore at subsurface geologic sites that include reliable sealing layers, appropriate geology, and good spatial location, such as those found in an exempted aquifer, a saline formation, or depleted oil and/or gas reservoirs. The CCS Protocol applies to both existing and new CCS projects provided the projects can meet the requirements for permanence pursuant to Section C of this protocol." (DTEER1_SF36-2)

Comment: CCS Protocol Appendix B 1. Applicability.

> *"The Carbon Capture and Sequestration (CCS) Protocol applies to CCS projects that capture carbon dioxide (CO_2) and sequester it onshore at subsurface geologic sites that include reliable sealing layers, appropriate geology, and good spatial location, such as those found in an exempted aquifer, a saline formation, or depleted oil and or gas reservoirs. The CCS Protocol applies to both existing and new CCS projects and existing CCS CO_2 injection wells if the projects and associated wells, provided the projects can meet the requirements for permanence pursuant to section C of this protocol."* (CIPA3_SF46-1)

Comment: Replace the proposed CCS Protocol Appendix B 1. A(1) Applicability with the following:

"The Carbon Capture and Sequestration (CCS) Protocol applies to CCS projects that capture carbon dioxide (CO_2) and sequester it onshore at subsurface geologic sites that include reliable sealing layers, appropriate geology, and good spatial location, such as those found in an exempted aquifer, a saline formation, or depleted oil and or gas reservoirs. The CCS Protocol applies to both existing and new CCS projects and existing CCS CO_2 projects, provided the projects meet the requirements for permanence pursuant to section C of this protocol." (MACPHERSON1_SF48-2)

Agency Response: Staff appreciates the suggested addition to subsection A(1) of the Protocol. However, staff did not modify the protocol in response to these comments, as the Protocol explicitly outlines the requirements of a site appropriate for geologic carbon sequestration.

M-4. Multiple Comments: *General Comments*

M-4.1 Multiple Comments: *Commentary Accompanying Technical Recommendations*

Comment: CIPA believes these comments would improve the oversight of a CCS project and provide safe CO_2 sequestration, while expanding the opportunities to identify and complete a sequestration project. That these changes provide flexibility in the CCS program to allow a successful CCS project to go forward, and providing California the ability to sequester CO_2 and reduce California's overall CI. (CIPA3_SF46-4)

Comment: Macpherson believes its comments are consistent with CARB's August 30, 2016 "Technical Discussion Series: Site Selection" work, and that these comments will:

- Improve the safety of a CCS project,
- Provide a scientific based regulatory managed pathway,
- Provide the flexibility necessary for a successful CCS project,
- Provide real CO_2 reductions, and
- Reduce California's overall CI.

(MACPHERSON1_SF48-5)

Comment: For the most part, we echo the comments the Clean Air Task Force and the Natural Resources Defense Council and others are submitting in this comment period, regarding several technical issues which were largely addressed in the current proposal. (NEXTGEN4_SF60-17)

Agency Response: Please see Response M-4 in Chapter IV.

M-4.2 Multiple Comments: *Continued Evolution of the CCS Protocol*

Comment: One final note on CCS, as the technology evolves and projects that are early adopters provide greater data and insight to CARB through mandated reporting and through an overall partnership with staff; it is our hope that the protocol will be given the opportunity to evolve to reflect a performance based standard much like the fuels that enter the program are evaluated. (WE4_SF20-4)

Comment: WSPA urges CARB staff to continue the effort to further improve the flexibility to allow for technology improvements and data based review to reduce the prescriptiveness of this document. (WSPA8_SF33-2)

Comment: WSPA urges CARB staff to continue the effort to further improve the flexibility to allow for technology improvements and data based review to reduce the prescriptiveness of this document. (WSPA9_SF34-2)

Comment: Conestoga has used carbon capture and sequestration (CCS) for years at our Arkalon Ethanol and Bonanza Bioenergy ethanol plants in Kansas to voluntarily avoid the atmospheric emission of millions of tons of CO_2 produced during the ethanol fermentation process. Conestoga supports the current CCS protocol and looks forward to working with CARB more closely to be one of its first adopters. We do hope CARB will use an adaptive management strategy to evolve the CCS protocol over time to incorporate lessons learned to simplify the protocol and more closely reflect the performance based standards used now to evaluate fuels. (CONESTOGA2_SF17-2)

Comment: To address these issues in a systematic fashion, we strongly urge that the Board adopt a resolution during its September, 2018 meeting, ensuring that these provisions will be further analyzed and revisited in the next calendar year pursuant to specific direction as follows:

> *WHEREAS carbon dioxide emission reduction projects using CCS can help California efficiently meet its 2030 LCFS and greenhouse gas reduction targets.*
>
> *WHEREAS the CCS Protocol requires 100 years of leak detection monitoring following cessation of injection.*
>
> *WHEREAS experience with CCS projects in California and worldwide will have increased significantly by the time such CCS projects regulated under the Protocol reach the post-injection phase.*
>
> *WHEREAS we anticipate that monitoring methods and strategies will evolve in the future as projects are permitted and undertaken.*
>
> *WHEREAS scientific methods to demonstrate plume stability, and the understanding of, and statistical data on, any residual risk of leakage of injected carbon dioxide will advance considerably over the coming decades.*

NOW, THEREFORE, BE IT RESOLVED that the Board directs the Executive Officer to work with stakeholders, including scientists and researchers, project developers and environmental groups, to evaluate the optimal methods and requirements for monitoring and leak detection of CCS projects and demonstration of permanence.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with stakeholders, including scientists and researchers, project developers and environmental groups, to evaluate and to determine under what circumstances it is scientifically supported and environmentally protective for monitoring and leak detections to either be continued for a defined period or to be discontinued following the cessation of injection and after plume stabilization has been established.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to propose amendments to the CCS Protocol that are informed by the stakeholder process and that specifically address the duration, frequency and nature of post-injection monitoring, including authorizing the termination of monitoring in the event that it can be demonstrated with a high degree of confidence that permanence will be achieved by a particular CCS project. (C2ESCATFEDFNRDC1_SF41-7)

Agency Response: Regarding the commenter's support for the Protocol in comment CONESTOGA2_SF17-2, please see Response M.1-1 in this chapter.

Please see Response M-4-2 in Chapter V regarding Board direction in Resolution 18-34 to monitor the development of science related to the implementation of the CCS Protocol under the LCFS, and to propose technical updates to the CCS Protocol, as needed.

M-4.3 Multiple Comments: *Out-of-State Projects*

Comment: The CCS protocol, however, does not address important questions as to how CARB will consider equivalence across jurisdictions. Rules established for CCS in other states, provinces and countries are different and may appear incompatible yet are no less effective for establishing permanent storage. WSPA recommends that the Protocol be amended to give the Executive Officer discretion to approve credit applications from out-of-state storage projects where local regulations may differ yet satisfy the same functional intent. (WSPA8_SF33-3)

Comment: The CCS protocol, however, does not address important questions as to how CARB will consider equivalence across jurisdictions. Rules established for CCS in other states, provinces and countries are different and may appear incompatible yet are no less effective for establishing permanent storage. WSPA recommends that the Protocol be amended to give the Executive Officer discretion to approve credit applications from out-of-state storage projects where local regulations may differ yet satisfy the same functional intent. (WSPA9_SF34-3)

Agency Response: Please see Response M-3.3 in Chapter IV.

M-5. Multiple Comments: *Concerns with Regulatory Language*

M-5.1 *Limiting Innovative Methods to On-Site Carbon Capture*

Comment: § 95489(c)(1)(A) of the LCFS defines an innovative method as:

> "[C]rude production or transport using…2. Carbon capture and sequestration (CCS). Carbon capture must take place onsite at the crude oil production or transport facilities."

Similarly, § 95490(a)(1) of the LCFS provides:

> "The following entities are eligible to submit project applications and, if approved, receive CCS credits, in accordance with following [the Protocol]…(1)…oil and gas producers that capture CO_2 on-site and geologically sequester CO_2 either on-site or off-site."

The requirement that CO_2 be captured on-site, is unnecessarily limiting and may inadvertently increase the cost and carbon intensity of fuels produced using carbon CCS. For example, one technology that is available to sequester CO_2 is enhanced oil recovery, or CO_2-EOR. Occidental is studying and developing technology to capture anthropogenic CO_2 from flue gases as well as reviewing the feasibility of direct air capture. The captured CO_2 will then be used in EOR. Occidental believes that it will be in position to submit an application to CARB that meets the CCS Protocol under development no later than 2019.

In preparing for such an eventuality, Occidental has analyzed the breadth of sources and methodologies for capturing CO_2. Sources of anthropogenic CO_2 include entities operating in several industry sectors such as ethanol and bio-refining, refining, iron and steel, cement, hydrogen production, natural gas processing, pulp and paper and ammonia. In some cases, it will prove more economically for carbon capture equipment to be located at a stand-alone centralized location rather than on site at crude oil production or transport facilities. In addition, eliminating the requirement that the carbon capture takes place on site at crude oil production or transport facilities will enable entities to positon capture facilities so as to optimize operations and minimize carbon intensity. For example, an entity could choose to re-use an existing but unused industrial location, take advantage of existing utilities and right-of-ways, perhaps even available renewable energy sources, avoid changed land uses and reduce impacts to the existing land use.

In addition, state oil and gas laws in California, Texas, New Mexico and other states may not consider the erection of carbon capture facilities on the surface interest overlying a leasehold interest to be reasonably necessary to search, develop and produce minerals. In California, Texas and New Mexico, a mineral-interest owner or an oil and gas lease may use as much of the surface when, where, and in such ways as are *reasonably necessary* to search for, develop and produce minerals. Occidental believes that the use of the surface carbon capture is reasonable, but an option of

locating carbon capture and sequestration facilities off-site is likely to prove more workable.

We suggest revising the language of § 95489(c)(1)(A) of the LCFS as follows:

> "[C]rude production using…2. Carbon capture and sequestration (CCS). Carbon capture may take place <u>either</u> onsite <u>or off-site</u> at crude oil production or transport facilities."

We suggest revising the language of § 95490(a)(1) of the LCFS as follows:

> "The following entities are eligible to submit project applications and, if approved, receive CCS credits, in accordance with following [the Protocol]…(1)…oil and gas producers that capture ~~CO_2 on-site~~ and geologically sequester CO_2 either on-site or off-site." (OCCIDENTAL5_SF21-2)

> **Agency Response:** The innovative crude production method provision was designed to promote those technologies that are truly innovative. Technologies included in the provision have been proposed by stakeholders and vetted through a deliberative process involving workshops, stakeholder feedback, and Board consideration. In order to qualify for credits via innovative crude methods, a project must capture CO_2 associated with oil production at an on-site facility. CO_2-EOR on its own is not considered innovative, as it has been used for decades. However, capturing CO2 from a steam generator at the oil production facility or from a methane reformer at a bitumen upgrader is considered to be innovative. The captured CO_2 may then be transported to another location or field for injection and sequestration. CO_2-EOR using only anthropogenic CO_2 that is not associated with oil production would not qualify as an innovative method. No modifications were made in response to this comment as the requirement is already sufficiently clear.

M-5.2 *Joint Applicants*

Comment: § 95490(c)(1) of the LCFS provides:

> "Unless otherwise noted, an application for CCS credits must comply with the following requirements: (1) An application must be filed jointly by an entity that captures CO_2 and an entity that sequesters the resultant CO_2, unless the same entity is responsible for CO_2 capture and sequestration."

A complete application package for CCS projects is crucial to ensure public confidence in a project and CARB's review. In many cases, the same entity will capture and sequester the CO_2 and, consequently, a single application will be submitted. In some cases, the entity capturing the CO_2 will transfer the captured CO_2 to a different entity that sequesters the CO_2. In some of these cases, a joint application may be appropriate. In other cases, it may be preferable that the entities maintain an arms-length relationship, e.g., where an entity that captures the CO_2 has contractual relationships with several entities that are sources of CO_2 and there may be sensitivity

to working with an entity that has access to competitive business information used to develop a joint application. In such cases, we suggest that it would be prudent for the LCFS language to be revised so the separate applications may be submitted by the entity that captures the CO_2 and the entity that sequesters the CO_2, with the Executive Officer's approval.

We suggest revising the language of § 95490(c)(1) of the LCFS as follows:

> "Unless otherwise noted, an application for CCS credits must comply with the following requirements: (1) Unless approved by the Executive Officer, ~~A~~ an application must be filed jointly by an entity that captures CO_2 and an entity that sequesters the resultant CO_2, unless the same entity is responsible for CO_2 capture and sequestration." (OCCIDENTAL5_SF21-3)
>
> **Agency Response:** Staff acknowledges the concerns of the commenter regarding joint applicants for CCS projects. Joint application for CCS projects is necessary to ensure that both parties are liable for the entire project and generated credits. This increases accountability for both parties and provides protection to the state to ensure that appropriate parties are responsible in the case of potential non-compliance. Staff does not believe that any modification to the Protocol is necessary, as the original language better achieves CARB's intent.

M-6. Multiple Comments: *Accounting Requirements*

M-6.1 Multiple Comments: *Leakage Assumption and Detection Limits*

Comment: Consistent with our previous comments, WSPA remains concerned with the continued emphasis on environmental baselines. In the December 15, 2017 WSPA comment letter, we expressed concern with the presumption of CO_2 leakage "equal to the detection limit of the equipment." Subsequently in the April 23, 2018 WSPA comment letter, we proposed: "if a default rate of leakage is to be assumed on the basis of detection limits, CARB should make a determination not necessarily on the basis of equipment, but by considering the leak detection 'methods' employed." The key question that remains unanswered is: how to agree on the precision of the leak detection method. WSPA requests that CARB address that question in the protocol. (WSPA8_SF33-5)

Comment: Consistent with our previous comments, WSPA remains concerned with the continued emphasis on environmental baselines. In the December 15, 2017 WSPA comment letter, we expressed concern with the presumption of CO2 leakage "equal to the detection limit of the equipment." Subsequently in the April 23, 2018 WSPA comment letter, we proposed: "if a default rate of leakage is to be assumed on the basis of detection limits, CARB should make a determination not necessarily on the basis of equipment, but by considering the leak detection 'methods' employed." The key question that remains unanswered is: how to agree on the precision of the leak

detection method. WSPA requests that CARB address that question in the protocol. (WSPA9_SF34-5)

Comment: B.2.2(e)

We continue to oppose the de-facto assumption of leakage at half the detection limit of the method(s) used to detect leaks as arbitrary, unfounded and redundant to Buffer Account contributions. If ARB continues to include such an assumption, we recommend consistency with 4.3.2(c)(2) which means setting the assumption of leakage at 5% of the detection limit of the method deployed. We also note that the provision, which appears additive, may penalize good behavior and redundancy by disincentivizing operators from deploying more detection methods. (CATFNRDC2_SF40-5)

> **Agency Response:** Regarding comment CATFNRDC2_SF40-5, staff disagrees with the commenter that the assumption of leakage at half the detection limit of the method(s) used to detect leaks is arbitrary, unfounded, and redundant to Buffer Account contributions. Please see Response M-8.6 in Chapter IV regarding the justification for the use of half the detection limit of the leak detection method.
>
> Staff notes that, for crediting purposes, calculations of injected CO_2 for CO_2-EOR (Equation 5 in the Protocol) and depleted oil and gas reservoirs and saline formations (Equation 6 in the Protocol) account for leakage of CO_2. A project's contributions to the Buffer Account, as estimated in Appendix G of the Protocol, are unrelated to the calculation of injected CO_2 in Equations 5 and 6. However, when retiring credits from the Buffer Account, leakage estimates are not double-counted, as they are already accounted for in Equations 5 and 6 of the Protocol.
>
> Staff also disagrees that the provision may penalize good behavior and redundancy by dis-incentivizing operators from deploying more or better detection methods. Please see Response M-8.6 in Chapter IV for staff's response to incentivizing improved detection.
>
> Regarding comments WSPA8_SF33-5 and WSPA9_34-5, staff clarifies that the value of half the detection limit of the leak detection method should be proposed by the operator, and is subject to approval by CARB.

M-6.2 Multiple Comments: *Project Risk Rating and Contribution to Buffer Account*

Comment: In Appendix G (Determination of a CCS Project's Risk Rating for Determining its Contribution to the LCFS Buffer Account), a CCS project's "overall risk rating and contribution to the Buffer Account" is calculated in equation G.1 which includes an extra 5% buffer. As a result, this extra 5% raises the buffer from a minimum of 3% to 8%. However, the extra 5% buffer is not mentioned or justified elsewhere in the CCSP. Further, the equation as written does not reflect project risk as there is no meaning to 105% certainty of an event. WSPA requests that the CCSP be amended to

include a description and justification of the extra 5% buffer with reference to equation G.1. (WSPA8_SF33-6)

Comment: In Appendix G (Determination of a CCS Project's Risk Rating for Determining its Contribution to the LCFS Buffer Account), a CCS project's "overall risk rating and contribution to the Buffer Account" is calculated in equation G.1 which includes an extra 5% buffer. As a result, this extra 5% raises the buffer from a minimum of 3% to 8%. However, the extra 5% buffer is not mentioned or justified elsewhere in the CCSP. Further, the equation as written does not reflect project risk as there is no meaning to 105% certainty of an event. WSPA requests that the CCSP be amended to include a description and justification of the extra 5% buffer with reference to equation G.1. (WSPA9_SF34-6)

> **Agency Response:** Please see Responses H-4, M-9.1, and M-9.2 in Chapter IV regarding the reasoning for increasing the percentage of credits that a project must contribute to the Buffer Account during a project's active life. As indicated in Appendix G of the Protocol, Equation G.1 allows the calculation of a CCS project's overall risk rating and contribution to the Buffer Account. Equation G.1 does not reflect project risk on an absolute scale (i.e., from 0 to 100%), but rather reflects relative risk levels that could be reduced through voluntary action, as well as the additional 5%. Staff did not make additional edits to the Protocol.

M-6.3 Multiple Comments: *Concerns with Buffer Account and Credit Issuance*

Comment: The language in Section C.3(c)(2), Invalidation and Buffer Account, states: *"Sequestered CO_2 must remain within the storage complex for at least 100 years in order to be considered permanently sequestered and subsequently credited."* This language could be interpreted to mean that credits will not be issued before 100 years have passed. Another interpretation is that after 100 years, credits in the Buffer Account will be credited to the project proponent. WSPA requests that CARB clarify this language. (WSPA8_SF33-7)

Comment: The language in Section C.3(c)(2), Invalidation and Buffer Account, states: *"Sequestered CO_2 must remain within the storage complex for at least 100 years in order to be considered permanently sequestered and subsequently credited."* This language could be interpreted to mean that credits will not be issued before 100 years have passed. Another interpretation is that after 100 years, credits in the Buffer Account will be credited to the project proponent. WSPA requests that CARB clarify this language. (WSPA9_SF34-7)

Comment: <u>B.3(c)(2)</u>

The phrasing "[...] sequestered and subsequently credited" implies that CO_2 must remain sequestered for 100 years before any credits associated with the injection can be issued. As we understand it, the structure of the Protocol allows for credits to be issued once CO_2 has been injected. (CATFNRDC2_SF40-6)

Agency Response: As alluded to in comment CATFNRDC2_SF40-6, the Protocol allows for credits to be issued following Permanence Certification by CARB and verified injection of CO_2. The language in subsection B.3(c)(2) of the Protocol does not mean that CO_2 must remain sequestered for 100 years before any credits associated with injection can be issued. Staff notes that this interpretation of the language in subsection B.3(c)(2) would negate the need for a Buffer Account as credits would be issued based on the actual quantity of CO_2 remaining permanently sequestered after 100 years.

M-7. Multiple Comments: *Permanence Certification*

M-7.1 *Third Party Reviewer Qualifications*

Comment: C.1.1.1(e) and C.1.1.1(f)

We recommend that ARB revise the professional credentials to read:

> "[...] or equivalent qualified professional ~~geologist/engineer~~ from California or another jurisdiction that is approved by the Executive Officer."

This change will avoid precluding highly qualified individuals with related credentials (e.g. petroleum engineers) from fulfilling the role. (CATFNRDC2_SF40-7)

Agency Response: Subsection C.1.1.1(b) of the Protocol requires that the third party review of an application for Sequestration Site Certification be conducted by a licensed professional geologist. As indicated by the contents of this application under Section C.1.1.2(b), this review requires a depth of knowledge and understanding of geology that is typically only possessed by professional geologists. Therefore, staff did not modify the Protocol to allow professionals in other disciplines to conduct this review. Similarly, subsection C.1.1.1(c) of the Protocol requires that a third party review of a CCS project certification be conducted by a licensed professional engineer. This review also requires a depth of knowledge and understanding of engineering that is typically only possessed by professional engineers, as indicated by the list of application requirements in subsection C.1.1.2(d). Staff notes that licensed professional petroleum engineers approved by the Executive Officer can conduct third-party reviews of CCS project certifications.

M-7.2 *Quarterly or Annual Reporting*

Comment: However, we recommend that ARB retain the right to request quarterly reporting if circumstances such as (suspected) leakage warrant it. (CATFNRDC2_SF40-9)

Agency Response: As indicated in subsection C.1.1.3.2 of the Protocol, CARB has provided flexibility in the frequency of reporting of GHG emissions reductions and ongoing monitoring results and verification of CO_2 sequestered for crediting purposes. Subsection C.4.3 of the Protocol requires continuous monitoring of

operating parameters that could signal potential leakage of CO_2, including the injection rate and volume as well as the injection pressure at the wellhead and downhole at each CCS injection well. Section C 1.1.3.5 requires that situations that result in suspected leakage be reported within 24 hours. As a result, detection and mitigation of a potential leakage should occur within a relatively short time-scale and should not be dependent on the frequency of reporting and verification of GHG emissions reductions.

M-8. Multiple Comments: *Site Characterization*

M-8.1 Multiple Comments: *Site Selection Criteria*

DTEER proposes to replace the existing language in 2.1(a)(5) in its entirety and replace with the following:

(5) "Depending on the distance between the sequestration zone and basement rock, the Executive Officer may require the CCS Project Operator to identify and characterize additional dissipation interval(s) below the storage complex, or describe active reservoir pressure management procedures (e.g., brine extraction) or other techniques to reduce seismic potential, to limit the extent of downward overpressure propagation and lower the potential for induced seismicity within formations beneath the injection zone." (DTEER1_SF36-5)

Comment: Site Characterization

2.1 Minimum Site Selection Criteria

(5) "Depending on the distance between the sequestration zone and basement rock, the Executive Officer may require the CCS Project Operator to identify and characterize additional dissipation interval(s) below the storage complex, or describe active reservoir pressure management procedures (e.g., brine extraction) or other techniques to reduce seismic potential, to limit the extent of downward overpressure propagation and lower the potential for induced seismicity within formations beneath the injection zone." (CIPA3_SF46-3)

Comment: Replace the current language in section 2.1 Minimum Site Selection Criteria with the following:

2.1 Minimum Site Selection Criteria

(5) "Depending on the distance between the sequestration zone and basement rock, the Executive Officer may require the CCS Project Operator to identify and characterize additional dissipation interval(s) below the storage complex, or describe active reservoir pressure management procedures (e.g., brine extraction) or other techniques to reduce seismic potential, to limit the extent of downward overpressure propagation and lower the potential for induced seismicity within formations beneath the injection zone." (MACPHERSON1_SF48-4)

Agency Response: Staff agrees that active reservoir management may have the potential to provide protection from seismic events equivalent to additional dissipation intervals. However, those techniques are not yet proven to staff's knowledge, and additional demonstration would be needed to include them into the Protocol. Given the available time and resources, staff was unable to complete a comprehensive review and analysis regarding reservoir pressure management. Staff intends to continue stakeholder engagement, consistent with Board Resolution 18-34, and will further evaluate these provisions and propose adjustments, as needed.

M-8.2 Multiple Comments: *Baseline Testing and Monitoring*

Comment: Section C.2.5(b)(2) states that the baseline strategy must be consistent with the risk assessment and modeling. Section C.2.5(c)(1) states *"The frequency and spatial distribution of baseline data collection must be designed according to a timeline and schedule set forth in the application for Sequestration Site Certification utilizing [sic] no less than one year prior to the initiation of injection."* Thus, Section C.2.5(c)(1) adds the word "utilizing" when the word "starting" would seem to be more appropriate. As written, it is not clear if one year of data is required or if the testing program must start at least one year before injection begins. WSPA requests clarification on this point. (WSPA8_SF33-8)

Comment: Section C.2.5(b)(2) states that the baseline strategy must be consistent with the risk assessment and modeling. Section C.2.5(c)(1) states *"The frequency and spatial distribution of baseline data collection must be designed according to a timeline and schedule set forth in the application for Sequestration Site Certification utilizing [sic] no less than one year prior to the initiation of injection."* Thus, Section C.2.5(c)(1) adds the word "utilizing" when the word "starting" would seem to be more appropriate. As written, it is not clear if one year of data is required or if the testing program must start at least one year before injection begins. WSPA requests clarification on this point. (WSPA9_SF34-8)

Agency Response: The requirement for the baseline monitoring strategy is the submittal of one year of data. CCS projects may choose to either:

1. Submit an application for Sequestration Site Certification outlining their baseline monitoring strategy, collect baseline data for one year, and then begin injection following the issuance of CCS Project Certification; or
2. Submit one year of previously collected data prior to applying for Sequestration Site Certification and CCS Project Certification at the same time.

M-8.3 *Core Analyses for Formation Testing*

Comment: However, we recommend that rock mechanical formation testing requirements should only apply where geologically appropriate, i.e. where there actually is an identifiable, representative primary confining layer. In carbonate or continental

clastic sequences, a discrete confining layer may not exist such that it is possible to identify a representative sample zone for the purposes of coring and attendant rock mechanical tests.

Moreover, it is important to note that sidewall coring may be damaging to wells, may not be representative compared to full cores, and may not provide added value in demonstrating integrity of the confining sequence. The operator should be required to justify a choice of subsurface sampling locations for geomechanical testing. If geomechanical testing or obtaining a representative sample is not possible, the operator should be required to provide other evidence of the confining system integrity and properties. Also, where robust information on the storage complex and its confining system is available, as is the case in some existing projects, an operator may be able to provide better information from existing historical data and testing. (CATFNRDC2_SF40-12)

> **Agency Response:** Staff acknowledges that geomechanical formation testing may only be identifiable in certain geologic settings. However, staff does not believe the suggested modification is needed, as nothing in subsection C.2.3.1 of the Protocol would prohibit staff from working with stakeholders to develop alternative data that supports the suitability of a storage complex to permanently sequester CO_2.
>
> Regarding the comment concerning the utilization of previously collected, historical data, staff would like to point out that subsection C.2.3.1(d) of the Protocol states that, "For existing CCS projects, historical data that provides a demonstration of the suitability of the selected storage complex for sequestering CO_2 may be submitted in lieu of the data required by subsections C.2.3.1(b) and (c), provided the data is determined by the Executive Officer to be equivalent or better than that required by those same subsections." Since operators were already allowed by the Protocol to submit historical data, no modifications to the Protocol are necessary.
>
> Finally, staff would like to point out that subsection C.2.3.1(f)(1) of the Protocol requires whole cores <u>OR</u> sidewall cores, not both. Therefore, staff did not make any modifications to the Protocol in response to the commenter's concerns about sidewall cores.

M-9. Multiple Comments: *Well Construction and Operating Requirements*

M-9.1 Multiple Comments: *Well Construction*

Comment: Section C.3.1(c)(5) now includes "(e.g., corrosion-resistant)". This example does not provide a useful amplification of the requirement to use materials compatible with the CO_2 stream and formation fluids. WSPA requests that CARB consider supplementing examples or delete the current example. (WSPA8_SF33-9)

Comment: Section C.3.1(c)(5) now includes "(e.g., corrosion-resistant)". This example does not provide a useful amplification of the requirement to use materials compatible

with the CO_2 stream and formation fluids. WSPA requests that CARB consider supplementing examples or delete the current example. (WSPA9_SF34-9)

> **Agency Response:** Staff disagrees with the commenter that the example provided by staff in subsection C.3.1(c)(5) of the Protocol does not provide a useful example of the requirement to use materials compatible with the CO_2 stream and formation fluids. This example, "(e.g., corrosion-resistant)", was added to the Protocol in response to previous comments; please see Response M-9.1 in Chapter V. Staff notes that corrosion resistance of well materials to the fluids with which they come into contact is important for reducing the likelihood of injection well failure and release of stored CO_2.

M-9.2 Multiple Comments: Injection Pressure

Comment: Section C.3.3(b) of the Protocol provides:

"The CCS Project Operator must ensure that injection pressure does not exceed 80 percent of the fracture/parting pressure of the sequestration zone…[t]he CCS Project Operator may propose an alternative injection pressure, provided the operator…(3) [r]eceives Executive Officer approval of the alternative pressure prior to injection."

Occidental appreciates the revisions to this section of the Protocol that create a performance standard that allows an applicant to demonstrate an appropriate alternative injection pressure. Occidental also agrees that an Executive Officer approval process is appropriate before a CCS project generates credits. In the case of CO_2-EOR project applications submitted pursuant to the Protocol, many will already be injecting at an alternative pressure and, as is the case with Occidental, may have 40 to 50 years of operating history to demonstrate its understanding of subsurface conditions including the frac/parting pressure. Executive Officer approval prior to generating credits is appropriate. However, if this provision were not revised, a narrow read of this requirement would preclude many CO_2-EOR operations from meeting Protocol requirements simply because they are already in operation.

We suggest revising the language of section C.3.3(b) of the Protocol as follows:

"The CCS Project Operator must ensure that injection pressure does not exceed 80 percent of the fracture/parting pressure of the sequestration zone…[t]he CCS Project Operator may propose an alternative injection pressure, provided the operator…(3) [r]eceives Executive Officer approval of the alternative pressure ~~prior to injection~~." (OCCIDENTAL5_SF21-4)

Comment: <u>C.3.3(b)</u>

We support the revised structure but recommend streamlining requirements with the Underground Injection Control Program, Class VI (40 C.F.R. § 146.88(a)) to not exceed 90% of the fracture/parting pressure. (CATFNRDC2_SF40-13)

Agency Response: Regarding comment OCCIDENTAL5_SF21-4, staff appreciates the commenter's support for staff's revision to the injection pressure limit in subsection C.3.3(b) of the Protocol. Project Operators of currently-operating CO_2-EOR projects are not prohibited from proposing an alternative injection pressure limit consistent with subsection C.3.3(b) of the Protocol. The requirement in subsection C.3.3(b)(3) to obtain Executive Officer approval of the alternative injection pressure prior to injection applies to LCFS crediting of CO_2 sequestered under the alternative injection pressure. In other words, CARB will only credit CO_2 sequestered under an alternative injection pressure above 80 percent of the fracture/parting pressure of the sequestration zone after Executive Officer approval of this alternative injection pressure.

Regarding comment CATFNRDC2_SF40-13, the addition of a third injection pressure limit in order to streamline requirements with the Underground Injection Control Program, Class VI is unnecessary and could be confusing. Therefore, staff did not incorporate this recommendation into the Protocol.

M-9.3 Injection Well Shutdowns and Alarms

Comment: C.3.3(f) and C.3.4(a)(3)

It is unclear what the purpose of the suggested addition of the term “un-remedied” is here. ARB should clarify the meaning of this term and how it impacts what will happen in practice when an automatic shutdown or alarm is triggered. (CATFNRDC2_SF40-14)

Agency Response: Please see Response M-9.6 in Chapter V.

M-10. Multiple Comments: *Injection Monitoring*

M-10.1 Multiple Comments: *Continuous Monitoring of Injection Pressure*

Comment: In section C.4.3.1.3(d), the following monitoring language has been added:

> *“(d) During injection, pressure in the annular space directly above the packer must be maintained at a pressure ~~least 100 to 200 psi~~ higher than the tubing pressure.”*

As written, the annular pressure is at or slightly above pressure as the injection stream, making it challenging to monitor for packer leaks. Further, keeping the casing continuously under pressure is problematic due to thermal expansion when switching from gas to liquid as would occur under water alternating gas EOR.

WSPA suggests the following performance-based language:

> *“(d) During injection, pressure in the annular space directly above the packer must be maintained at a pressure high enough to maintain a safety factor below the packer differential pressure rating. The owner or operator will propose a working annulus pressure range to the Executive Officer for approval. This*

annulus pressure range will take into account factors such as: tubular and equipment pressure ratings, thermal effects, variations in injection pressures, shut-in periods, and start-up procedures following initial well startup period."

(WSPA8_SF33-10)

Comment: In section C.4.3.1.3(d), the following monitoring language has been added:

"(d) During injection, pressure in the annular space directly above the packer must be maintained at a pressure ~~least 100 to 200 psi~~ higher than the tubing pressure."

As written, the annular pressure is at or slightly above pressure as the injection stream, making it challenging to monitor for packer leaks. Further, keeping the casing continuously under pressure is problematic due to thermal expansion when switching from gas to liquid as would occur under water alternating gas EOR.

WSPA suggests the following performance-based language:

"(d) During injection, pressure in the annular space directly above the packer must be maintained at a pressure high enough to maintain a safety factor below the packer differential pressure rating. The owner or operator will propose a working annulus pressure range to the Executive Officer for approval. This annulus pressure range will take into account factors such as: tubular and equipment pressure ratings, thermal effects, variations in injection pressures, shut-in periods, and start-up procedures following initial well startup period." (WSPA9_SF34-10)

Agency Response: Staff appreciates the suggestions but believes the current language is appropriate at this time. Staff will continue to investigate how to improve the Protocol during implementation. No modifications to the Protocol were made as a result of this comment.

M-10.2 *Pressure Fall-Off Test Requirements*

Comment: Section C.4.3.1.5(a) of the Protocol provides:

"CCS Project Operators must perform a pressure fall-off test of each well…[t]he CCS Project Operator may propose an alternative test method and/or schedule, provided the operator…(3) [r]eceives Executive Officer approval of the alternative test method and/or schedule prior to operation."

As with Section C.3.3(b) of the Protocol, the revisions to this section create a performance standard that permits an applicant to demonstrate an appropriate alternative test method and/or schedule. Again, CO_2-EOR project applicants will already be in operation. Executive Officer approval prior to generating credits is appropriate. However, if this provision were not revised, a narrow read of this

requirement would preclude many CO_2-EOR operations from meeting Protocol requirements simply because they are already in operation.

We suggest revising section C.4.3.1.5(a) of the Protocol as follows:

> "CCS Project Operators must perform a pressure fall-off test of each well…[t]he CCS Project Operator may propose an alternative test method and/or schedule, provided the operator…(3) [r]eceives Executive Officer approval of the alternative test method and/or schedule ~~prior to operation~~." (OCCIDENTAL5_SF21-5)
>
> **Agency Response:** Similar to Response M-9.2 in this chapter, CO_2-EOR projects are not prohibited from meeting the Protocol requirements because they are already in operation. Subsection C.4.3.1.5(a) of the Protocol requires operators to obtain Executive Officer approval of the alternative test method and/or schedule and applies to LCFS crediting of CO_2 sequestered under the alternative test method and/or schedule. CARB will only credit CO_2 sequestered under an alternative test method and/or schedule after Executive Officer approval of the alternative method/schedule.

M-10.3 *Surface and Near-Surface Monitoring*

Comment: C.4.3.2.2

Field investigations and monitoring trials described in peer-reviewed literature since the promulgation of the Federal UIC Class VI rule suggest that surface methods are unreliable due to variability in soil-gas concentrations as a result of seasonal changes, changes in nearby land use, climate change, and other reasons. Instead of mandating the use of these methods, we suggest that subsurface methods that can be shown to be equivalent or better to surface and near-surface methods be allowed in place of surface methods at the discretion of the Executive Officer if they can provide early warnings for injection well shutdown or CO_2 migration out of the storage complex before CO_2 can reach the atmosphere. (CATFNRDC2_SF40-16)

> **Agency Response:** Please see Response M-4.2 in Chapter V regarding surface monitoring methods.

M-10.4 *Monitoring, Measurement, and Verification Plan Requirements*

Comment: C.4.3.2(c)(2)

Requiring "a detection threshold equal to, or better than, 5% the total volume of leaked CO_2" is problematic and not useful in devising a monitoring, measurement and verification plan, since the volume of leaked CO_2, if any, cannot be known in advance. From the standpoint of atmospheric emissions and LCFS program crediting integrity, an absolute detection threshold is more relevant than a relative one. ARB could set an absolute limit, but a prerequisite would be a technical review of current technical capabilities for leak detection. Alternatively, ARB could retain the 5% formulation here

and instead base it on quantities predicted for leakage events considered in the project risk assessment. (CATFNRDC2_SF40-15)

> **Agency Response:** Staff examined the potential for an absolute detection limit, but did not institute one due to the lack of sufficient evidence demonstrating what a technically achievable detection limit would be. Staff settled on the 5% threshold as a mirror to the detection method accuracy requirements of CARB's climate programs. No modifications were made in response to this comment.

M-11. *Monitoring*

M-11.1 Multiple Comments: *Post Injection Site Care and Closure*

Comment: Our comments below are limited to the topic of post-injection monitoring for geologic sequestration projects. We recognize and appreciate the improvements that ARB has made to other aspects of the Protocol, but the provisions pertaining to post-injection monitoring require further revision in order to achieve ARB's goal of developing and implementing a Protocol that is fully informed by the best available scientific knowledge and maximizes environmental protection. (C2ESCATFEDFNRDC1_SF41-1)

Comment: Over the past several months, we have repeatedly raised our concerns with ARB on the proposed post-injection monitoring provisions, and have submitted extensive supportive material to the record. Most recently, the concerns expressed in CATF and NRDC's July 5th, 2018 comments have not been adequately addressed by the second 15-day revisions.

ARB staff is proposing some limited changes in the second 15-day version of the Protocol that are directionally correct. For example, the Protocol now allows for more generic class of monitoring methods ("near-surface") in place of specific methods that have already proven to be problematic in practice (soil gas monitoring).[1]

However, the overall rationale and problematic structure of the previously proposed versions remain unchanged. The requirements for monitoring after plume stabilization has been demonstrated do not afford the degree of environmental protection that is feasible, and are insufficiently informed by today's best science and practices.

[1] Protocol at proposed § 5.2.(b)(3)(G)(2) (p. 120).

(C2ESCATFEDFNRDC1_SF41-2)

> **Agency Response:** Staff disagrees with the commenter that the Protocol needs further modification to provide sufficient protection for CCS projects. Regarding continual updates to accommodate changes in technical understanding, please see Response M-4.2 in Chapter V.

M-11.2 Multiple Comments: *Concerns with 100-Year Monitoring Provision*

Comment: We note that the Post-injection site care and monitoring period is specified as a minimum of 100 years. This period is significantly longer than other comparable

regulations on CO_2 storage, and we do not see any evidence-base provided in the Protocol for this period. The evidence-base that is publicly available supports both a shorter period and some discretion by the regulator in determining the period for each case. This evidence-base is provided by the IPCC Special Report on CCS (2005) which shows for example that CO_2 storage becomes more secure with time, and the IPCC Guidelines for Greenhouse Gas Inventories (2006) which recognizes this aspect and allows for a zero leakage assumption if evidence from monitoring and modelling indicates no leakage. This IPCC evidence was used by the EU in the development of the CCS Directive (2009) and ETS Directive (2009), whose post injection site care equivalent is for a minimum of 20 years which can be earlier if the authority is convinced that "all available evidence indicates that the stored CO_2 will be completely and permanently contained". Note that in addition, the EU Directive requires a financial contribution to the authority to be able to monitor for a further 30 years if necessary. The CCS Directive was extensively reviewed in 2014 and found fit for purpose and no case made that these periods should be changed (Triple E 2015).

The same evidence base with updated evidence from further experiences (Dixon 2011) was used by the UNFCCC in the development of the rules (Modalities and Procedures) for CCS in the Clean Development Mechanism (UNFCCC 2011). These require monitoring of at least 20 years after the last crediting period, and then it can cease if no seepage has been observed at any time in the past 10 years and "if all available evidence from observations and modelling indicates that the stored carbon dioxide will be completely isolated from the atmosphere in the long term".

We also note that the US EPA Class VI rule requires 50 years of post-injection site care, which "could be shortened by the Director after cessation of injection if the owner or operator could demonstrate that USDWs would not be endangered prior to 50 years".

All of these examples have the post injection site care period equivalents based upon evidence-based assessments.

Since these regulations have been developed, there has been further substantial increase in the knowledge gained from real project experiences as well as further R&D and modelling in understanding the behavior of CO_2 in the subsurface and environment. This further knowledge reinforces the earlier evidence in these aspects. A review of this updated knowledge and experience was provided for the 10th anniversary of the IPCC Special Report by a Special Issue of the International Journal of Greenhouse Gas Control (2015).

Such evidence-based assessments for post injection site care are further facilitated by the availability of peer-reviewed tools to enable storage performance assessment by operators and by regulators. Such tools are provided by US DOE NETL in their National Risk Assessment Partnership program, with a range of peer-reviewed tools and guidance available at https://edx.netl.doe.gov/nrap/.

We suggest that the evidence base and tools for assessment exist for at least flexibility to be allowed in the Post-injection site and monitoring period in the Carbon Capture and

Sequestration Protocol under the Low Carbon Fuel Standard, if not actually a reduced period to be more in line with international best practice. (IEAGHG1_SF3-1)

Comment: As such, we continue to believe that the Protocol creates the illusion of rigorous oversight through field monitoring over the entire 100-year permanence period without ensuring the environmental protection associated with a fit-for-purpose monitoring strategy, and fails to fully leverage current and future scientific understanding of geologic sequestration and technological capabilities. (C2ESCATFEDFNRDC1_SF41-6)

Comment: Specifically, we agree that the blanket application of a 100 year monitoring, with the current prescribed monitoring methods is unscientific, cost-inefficient, and inadequately protective against leakage risk. The types of geological sequestration of pressurized CO_2 covered by this provision typically entail active injection periods well in excess of a decade. Given that no projects have even been conceptualized, much less constructed, at this point, post-injection monitoring will likely not begin for at least 20 years. During that time, we strongly expect technological advances in fields relevant to CCS monitoring. Future measurement techniques are likely to be more accurate and less costly than those specified in the current proposal. CARB should not tie project developers to requirements that they utilize analytical methods which will almost certainly be obsolete by the time they become relevant in the case of projects being credited under the LCFS.

Given the lack of real-world experience with CCS, we recognize that the first generation of commercial scale projects will entail real, though probably modest risk that the stored carbon could escape. We commend staff for the thought and effort they have made to design a program which can manage this risk. Given the critical need to deploy CCS at commercial scales, it may be prudent for CARB to temporarily adopt a view of risk that slightly diverges from precedent, for the first few projects which utilize this pathway. Because of the immense uncertainty regarding first-generation commercial-scale CCS projects, when risk is accurately priced into development costs, projects may become too expensive for any developer to accept, even after considering the value of LCFS credits. CARB may wish to partially limit reversion risk or liability in case of technical failure, for developers of the first small handful of projects. The critical importance CCS could play in global GHG reduction efforts requires rapid deployment of commercial-scale pilot projects, to begin to develop the corpus of real-world experience necessary to inform decision-making about the role of CCS in climate policy going forward. In essence, CARB may wish to consider a slightly more permissive approach to risk-management the first handful of pilot projects which can help inform the development of more robust and empirically-supported future CCS policy. While this means California will accept the risk that a leak at a CCS project may not be fully compensated for by the developer, the potential payback from developing CCS technology to commercial viability is so great that a strictly limited exception may be warranted in this case. (NEXTGEN4_SF60-18)

> **Agency Response:** See Response M-6 in Chapter IV regarding the 100-year monitoring provisions.

M-11.3 Multiple Comments: *Concerns with Seismic Monitoring Requirements*

Comment: WSPA interprets the mapping of the three-dimensional (3-D) extent of the free-phase CO_2 plume under C.5.2(b)(3)(E)(2) to apply only to the period up to determination of plume stability. Continued use of best-practice methods including 3-D seismic would be both unnecessary and potentially disruptive to enjoyment of activity on the surface. (WSPA8_SF33-11)

Comment: WSPA interprets the mapping of the three-dimensional (3-D) extent of the free-phase CO_2 plume under C.5.2(b)(3)(E)(2) to apply only to the period up to determination of plume stability. Continued use of best-practice methods including 3-D seismic would be both unnecessary and potentially disruptive to enjoyment of activity on the surface. (WSPA9_SF34-11)

> **Agency Response:** Staff agrees with the commenters, in that mapping the three-dimensional extent of the free-phase CO_2 plume under subsection C.5.2(b)(3)(E)(2) of the Protocol applies only to the period up to determination of plume stability. No modifications to the Protocol are necessary based on these comments, as the mapping requirement must follow the Post-Injection Site Care and Site Closure Plan, which must include the measurement frequency and the proposed schedule for submitting post-injection site care monitoring results to the Executive Officer (see subsection C.5.2(a)(2) of the Protocol).

M-11.4 Multiple Comments: *Concerns with Language in Sections C.5.2(b)(3)(G)(1) and 5.2(b)(3)(G)(2)*

Comment: In Sections C.5.2(b)(3)(G)(1) and C.5.2(b)(3)(G)(2), new language has been presented regarding Post-injection Site Care (PISC).

Specifically, leak detection strategy is described as follows:

1. *"In the near surface strategically located near plugged and abandoned wells, using ground-based methods. Aerial technologies with a likelihood of detecting leakage from wells in the near-surface equivalent to that of ground-based methods may be used, pending approval of the Executive Officer;"*
2. *"At areas of concern determined by the risk assessment (following subsection C.2.2) to be potential pathways for the preferential migration of CO_2 or brine to surface, during the post-injection site care and monitoring period at a frequency based on monitoring and verification data collected during injection and using methods approved by the Executive Officer, at a minimum of once every five years;"*

WSPA is supportive of this approach but is concerned that implementation duration of this strategy has not been addressed.

WSPA recommends that the following be added to Section C.5.2(b)(3)(G)(2):

2. *"At areas of concern determined by the risk assessment (following subsection C.2.2) to be potential pathways for the preferential migration of CO_2 or brine to surface, during the post-injection site care and monitoring period at a frequency based on monitoring and verification data collected during injection and using methods approved by the Executive Officer, at a minimum of once every five years for up to 100 years following cessation of injection;"*

This additional language will provide a CCS Project Operator the opportunity to request from the Executive Officer approval to discontinue aerial monitoring pursuant to clear demonstration over a period less than 100 years of leakage risk. (WSPA8_SF33-12)

Comment: In Sections C.5.2(b)(3)(G)(1) and C.5.2(b)(3)(G)(2), new language has been presented regarding Post-injection Site Care (PISC).

Specifically, leak detection strategy is described as follows:

1. *"In the near surface strategically located near plugged and abandoned wells, using ground-based methods. Aerial technologies with a likelihood of detecting leakage from wells in the near-surface equivalent to that of ground-based methods may be used, pending approval of the Executive Officer;"*
2. *"At areas of concern determined by the risk assessment (following subsection C.2.2) to be potential pathways for the preferential migration of CO_2 or brine to surface, during the post-injection site care and monitoring period at a frequency based on monitoring and verification data collected during injection and using methods approved by the Executive Officer, at a minimum of once every five years;"*

WSPA is supportive of this approach but is concerned that implementation duration of this strategy has not been addressed.

WSPA recommends that the following be added to Section C.5.2(b)(3)(G)(2):

2. *"At areas of concern determined by the risk assessment (following subsection C.2.2) to be potential pathways for the preferential migration of CO_2 or brine to surface, during the post-injection site care and monitoring period at a frequency based on monitoring and verification data collected during injection and using methods approved by the Executive Officer, at a minimum of once every five years for up to 100 years following cessation of injection;"*

This additional language will provide a CCS Project Operator the opportunity to request from the Executive Officer approval to discontinue aerial monitoring pursuant to clear demonstration over a period less than 100 years of leakage risk. (WSPA9_SF34-12)

Agency Response: Monitoring of the sequestration site is required for 100 years post injection. If aerial monitoring is approved, it may be used through the entirety of the 100 year PISC period, at an interval approved by the Executive Officer. If the operator would like to elect to transition to a different monitoring

strategy for the remainder of the PISC period, the new strategy would be subject to review and approval by the Executive Officer (see Response M-6 in Chapter IV).

M-11.5 Multiple Comments: *Plume Stability Determination*

Comment: In Section 5.2(b)(3)(F), it appears to switch from demonstration of plume stability to "determined by CARB". Given the lack of a clear technical definition of plume stability, WSPA requests that CARB to rely upon the professional judgement of a 3rd party verifier to make this determination. (WSPA8_SF33-13)

Comment: In Section 5.2(b)(3)(F), it appears to switch from demonstration of plume stability to "determined by CARB". Given the lack of a clear technical definition of plume stability, WSPA requests that CARB to rely upon the professional judgement of a 3rd party verifier to make this determination. (WSPA9_SF34-13)

Agency Response: Third-party verified data and professional judgement will be among the information that CARB uses to determine whether plume stabilization has occurred, however the ultimate determination will rest with CARB. No modifications were made in response to these comments.

M-11.6 Multiple Comments: *Post-Injection Monitoring*

Comment: The proposed subset of monitoring methods is too limited and hampers both the project operator's ability to select the best tools and strategies for monitoring, and also ARB's capability to accurately evaluate post-injection risk. Importantly, monitoring at depth will in most cases afford more reliable and timely warnings of leakage than near-surface monitoring. (C2ESCATFEDFNRDC1_SF41-3)

Comment: The value of historical project performance and compliance with the extensive preventative provisions of the Protocol is not utilized to inform whether post-injection monitoring should be modified based on site-specific conditions. (C2ESCATFEDFNRDC1_SF41-4)

Agency Response: Regarding the concerns about staff's updates to the monitoring methods, including near-surface monitoring, please see Response M-4.2 in Chapter V. In addition to the utilization of new data, each of the plans required by the CCS Protocol are iterative, and should be based on, and informed by, the data and interpretations collected and derived from prior versions of the plan. Hence, the focus on periodic updates to plans. Historical project performance and compliance must be considered in each plan iteration.

M-11.7 *Geologic versus Forest Carbon Sequestration*

Comment: Geologic sequestration, accompanied by monitoring and verification, is fundamentally different and has a longer-lasting carbon reduction benefit compared to the shorter-term benefit and inherent impermanence risks of forest carbon sequestration, where the 100-year post-injection monitoring requirements in question

appear to have their roots. Therefore, monitoring and verification approaches in geologic storage require a different treatment than those in ARB's Forest Offset Protocol. (C2ESCATFEDFNRDC1_SF41-5)

Agency Response: Please see Response M-6 in Chapter IV.

M-12. ***Binding Agreements***

Comment: Section C.9.(c) of the Protocol provides:

> "The CCS Project Operator must show proof that there is a binding agreement among relevant parties that drilling or extraction that penetrate the storage complex are prohibited to ensure public safety and the permanence of stored CO_2."

CO_2-EOR takes place in active oil and gas fields and may occur in different formations that lie on top of each other at different depths. The mineral estate, sometimes called the working interest, at each depth may be owned by the same or different entities. Occidental can demonstrate that it has a legally enforceable right to exclude other parties from drilling into and extracting from its working interest. This right may not be reflected in the express language of a lease but is enforceable at law.

We understand this Protocol provision to cover drilling into and extraction from the storage complex by an entity other than the CCS Project Operator. We do not understand it to cover wells drilled through a storage complex that do not have perforations in the well bore such that fluids in the storage complex could be withdrawn or risk leakage – this would be trespass. The working interest does not and cannot prevent an entity other than the CCS Project Operator from drilling through a formation that may include a storage complex to access another deeper resource or formation. Others may advance a well through the storage complex to reach a deeper mineral interest, to extract water, or to inject pursuant to the Safe Drinking Water Act ("SWDA"). In the case of oil and gas producing wells (Class II wells) or other injection wells, the SDWA requires states that have applied for primacy to demonstrate their standards are effective in preventing endangerment of US drinking water sources ("USDW").[1] The drilling techniques that are used to protect USDW prevent the release of CO_2 from a CO_2-EOR project during the drilling and construction of wells.

We suggest revising Section C.9.(c) of the Protocol to clarify the intention of this provision:

> "Upon injection completion, The CCS Project Operator must show proof that there is a binding agreement among relevant parties that drilling <u>and</u> ~~or~~ extraction <u>wells</u> that penetrate the storage complex are prohibited to ensure public safety and the permanence of stored CO_2. <u>Proof may be in the form of enforceable actions at law that permit a leaseholder to prevent others from accessing or trespassing on their leasehold or regulatory or other legal mechanisms that require wells that penetrate the confining layer above the sequestration zone to prevent unauthorized mixing or loss of fluids from the sequestration zone and confining layer</u>.

[1] EPA may grant primacy for all or part of a state's UIC program. E.g.,Texas and New Mexico have primacy for UIC Class I through V wells, CA has primacy for Class II wells. (OCCIDENTAL5_SF21-6)

Agency Response: Please see Responses M-23 in Chapter IV and M-13 in Chapter V.

N. Reporting and Recordkeeping

N-1. *Support for the Proposed Modifications to the Reporting and Recordkeeping Provisions*

N-1.1. *Support for the Proposed Change of Ownership or Operational Control Provisions*

Comment: REG supports allowing 30 days in 95483.3 on the change of ownership. (REG4_SF65-3)

> **Agency Response:** Staff appreciates the commenter's support for the proposed change to allow up to 30 calendar days for the previous and new owner of a registered entity or a facility to notify the CARB about the change of ownership of a registered entity or a facility.

N-1.2. *Support for the Proposed Fuel Transaction Reconciliation Requirements*

Comment: REG supports the clarification in 95486(a)(1)(B) with the reconciliation requirements being on obligated amounts. This will help avoid potential issues below the rack and other sales without obligation. (REG4_SF65-4)

> **Agency Response:** Please see Response N-1.2 in Chapter V.

N-2. Multiple Comments: *LCFS Reporting and Credit Issuance Timelines*

Comment: REG remains **adamantly opposed** to credits being generated on the day after the reporting deadline per (b) <u>unless</u> those deadlines are moved up to avoid moving from a 1 quarter delay to a 2 quarter delay on LCFS credit generation. As noted in prior comments, there are financial impacts from this proposal (estimated $0.13/gallon for an illustrative biodiesel producer).

This change will undoubtedly impact smaller and less well capitalized entities, whether they may have grasped the potential impact in their responses to CARB or not. Therefore, we continue to strongly encourage CARB staff to either move up the deadlines to the 20th of the last month for LCFS credit generation or allow liquid fuels opportunities for infrastructure projects as we suggested in July 2018 comments on 95486.2. (REG4_SF65-6)

Comment: As noted 95486, REG strongly advocates to keep the credit generation system as is. However, if it is changed so that no credits can be generated until after the reporting period is over, then we strongly recommend changing the reporting frequency and deadlines from 45/45 to 45/35 with deadlines being the 20th of the final month (June, September, December, and March) to avoid financial and working capital impacts. (REG4_SF65-11)

> **Agency Response:** Please see Response N-7.2 in Chapter IV.

N-3. ***Proposed Product Transfer Documents Requirements***

Comment: REG has concerns about a few changes proposed to the PTD requirements in (b)(1). First, the change to (b)(1), (b)(1)(F), (b)(2), and (b)(2)(B) will complicate transactions quite a bit so we recommend keeping the current language as is ("LCFS obligation is passed."). For instance, when REG is passing obligation in the state of California, the credits have already been generated since they are generated off of import. Under the proposed change, a statement saying, "the LCFS obligation to act as credit generator," would imply a second generation of credits. (REG4_SF65-12)

Agency Response: Please see Response N-5.2 in Chapter V.

O. Third-Party Verification

O-1. *Conflict of Interest and Availability of Qualified Verifiers*

O-1.1. Multiple Comments: *Firm Rotation Requirements, Availability of Qualified Verifiers, Lookback and Phase-In Period*

Comment: DTEBE has noted in previous comment letters that the stringent conflict of interest provisions for LCFS verification may have the unintended effect of limiting the pool of potential verifiers. This will result in a high cost for verification services and may lead to difficulty in securing adequate services for large producers like DTEBE. CARB has addressed this by delaying the phase-in of conflict of interest provisions to 2023 in the previous amendment package. In this amendment package in 95503(c)(3), CARB appears to exempt audit services provided pursuant to the U.S. EPA RFS program from assessment under a risk category (apart from third-party engineering reports as outlined in 95503(b)(2)(A)). However, this exemption appears to directly conflict 95502(b)(2)(A), which names "providing validation or verification services pursuant to U.S. EPA RFS" as a high potential conflict of interest condition. DTEBE requests that CARB add clarifying language to make clear that services pursuant to U.S. EPA RFS are exempt from assessment under a risk category. Clarifying this will go a long way towards ensuring a more robust ecosystem of verification service providers for the LCFS program. (DTEBE3_SF19-2)

Comment: We have previously stated in numerous public comment letters that we believe the firm rotation requirement should be removed from the proposed rule and continue to support that opinion. At the same time, we do understand that it is helpful to have someone new review audit and verification data, and we would support a lead verifier rotation on the LCFS verifications.

In past letters, we have cited numerous reasons why the firm rotation is not necessary for this proposed rule. The additional auditor independence, objectivity, and professional skepticism gained from a firm rotation does not outweigh the substantial cost, efficiency, and effectiveness lost. The Public Company Accounting Oversight Board (PCAOB) has done extensive research on this topic, which included auditing certified public accounting firms and collecting a vast amount of data supporting their stance of only requiring audit partner rotation.

They have noted that most of the errors that go unnoted were due to lack of technical competence or experience, insufficient supervision or deficiencies in the firm methodologies, not pro-client bias going into the engagement.

CARB has also reserved the right to audit the verification bodies. If there are concerns with long-standing relationships, we would suggest that CARB specifically choose some of these verification reports to audit so that they can ensure that the longstanding relationship is not having an effect on the auditor's independence or professional skepticism. If CARB feels that there is bias in the procedures being performed due to the relationship, then rotation could be required at that time.

Finally, we also wanted to call attention to the limited effect the firm rotation will have for the verifications. It is very likely with the limited pool of verifiers that the regulated parties will identify two firms that they are comfortable with and will rotate between those two firms. This means that there are essentially two audit teams that they will always work with and will get limited exposure to new firms and new procedures. This limited benefit is not worth the added cost and lost effectiveness of the verifications through firm rotation. Including a lead verifier rotation would provide a new look at the data while still maintaining the verification team staff and the efficiencies gained with their knowledge and experience with the regulated party.

Finally, we also would like CARB to consider the firm rotation's effect on other renewable fuel compliance programs and services. CARB has worked very hard at understanding other programs and has modified various items in the regulation to help gain efficiency from other fuel programs and accounting services already provided to the regulated parties. It is very likely that because of the efficiencies gained through other services that rotation of the LCFS verification body could also cause rotation and added costs in other program areas as well, including the QAP and RIN attest services. We again, highly suggest a lead verifier and independent verifier rotation to capture the benefit of a new verifier while still maintaining efficiencies at the staff level of the engagement and on other fuel program engagements. (CHRISTIANSON2_SF10-3)

Comment: *Verification of Fuel Pathways.* Growth Energy also has concerns regarding CARB's proposal to require verification of all fuel provider pathways. This proposed process is unnecessary because it would be duplicative of the work already performed as part of the pathway approval, and would add significant expense by requiring fuel providers to retain verifiers. This is of significant concern because CARB's proposed conflict of interest (COI) requirements are exceedingly stringent, and would dramatically limit the number of qualified third-party verifiers competent to serve as verifiers. Before considering the Proposed Amendments for adoption, CARB should survey the range of potential consultants available to serve as verifiers, and confirm the work is capable of being performed in a timely and cost-effective manner by existing competent professionals. Moreover, instead of requiring all alternative fuel producers to be subject to verification, CARB should instead impose random third-party verification for a small subset of alternative fuel producers each year (i.e., 5%). Random verification would be equally effective in ensuring compliance, but without the significant expense associated with *requiring* continuing verification for all alternative fuels. (See Exhibit "B" at 6.) (GROWTHENERGY3_SF31-6)

Comment: CARB Should Decline to Require Verification of all Fuel Provider Pathways, and Should Instead Implement Random Third-Party Verification of a Small Proportion of Pathways

As has been extensively noted in the public comments, the proposed requirements for verification of fuel producer pathways and annual pathway reports by accredited third parties will impose substantial burdens on producers of low-CI fuels, including ethanol.

First and foremost of these burdens is the cost of paying the verifier for the same work that in-house compliance teams and/or consultancies have already completed, as accredited verifiers will essentially be duplicating work performed as part of LCFS pathway application and reporting purposes. The second is a potential lack of verifiers to choose from given the proposed requirements related to conflicts of interest.

In order to become CARB-accredited, potential verifiers must submit an application to CARB including a self-evaluation of potential conflict of interest (COI) that may exist between them and the fuel provider (e.g. regulated entity or party) that they will be performing verification services for during the "look back period, which is 5 years prior to the start of verification. Any potential COI is also required to be monitored during the year of verification as well as one year after verification services are completed. If "high" conflicts of interest are found to be present, verifiers may be disqualified from providing verification services to specific fuel providers.

The following are some of the services identified in the proposed regulation as posing high potential for conflicts of interest:

1. Regulated party shares any management staff that have been employed by the verification body or vice versa.

2. Verifier or its company has previously provided the following services:

    - Designing, developing, implementing or maintaining data for CARB's Mandatory Reporting Regulation MRR reporting;
    - Developing CI or fuel transaction data or other GHG engineering analysis;
    - Providing consultative engineering or technical services related to fuel production facility that explicitly identify GHG reductions as a benefit;
    - Conducting internal audit or maintaining a GHG reduction offset project as defined per Cap-and-Trade regulation, or a project to receive LCFS-based credits;
    - Preparing LCFS fuel pathway applications or LCFS reporting manuals;
    - Managing health, environment or safety functions of the entity;
    - Services related to the development of information systems or consulting on the development of environmental management systems except for accounting management systems.
    - Reporting or uploading data on behalf of entity;
    - Owning, buying, selling, trading or retiring LCFS credits;
    - Dealing, brokering or promoting credits on behalf of entity;
    - Appraisal services of GHG liabilities or assets;
    - Internal audits related to internal accounting controls or financials;

- Any legal services; and
- Expert services to an entity or its trade group related to litigation or regulatory investigation.

3. The verification body cannot provide any monetary or non-monetary incentives to secure contract.

Based on the above, many qualified companies would not be able to receive CARB verifier accreditation creating an issue for regulated parties as there likely to be a very limited number of verifiers to choose from. Another problem is that the COI requirements make it difficult for large, reputable consulting firms to become accredited verifiers due to their corporate associations. These companies generally provide a large range of environmental consulting services on a disaggregated bases from separately-managed offices and locations.

Although the second 15-day notice provides some limited relief related to the issue of third-party verification, it does not address the fundamental problems identified above.

As an alternative to the current CARB proposal, Growth Energy strongly suggests eliminating the applicability of verification requirements to all of the subject regulated entities. CARB should instead require random third-party verification of only a small fraction regulated parties; for example, 5% of regulated entities each year. Clearly, having all regulated entities potentially being subject to a random verification will be close to, if not as effective, as mandatory verification in ensuring compliance but will impose a much smaller financial burden on fuel providers.
(GROWTHENERGY3_SF31-16)

> **Agency Response:** In response to the comments above, please see Responses O-2.1, O-2.2, and O-2.3 in Chapter IV addressing concerns about conflict of interest provisions and availability of qualified verifiers.
>
> In response to DTEBE3_SF19-2, staff would like to clarify that section 95503(b)(2)(A), as modified in its 2nd 15-day proposal, does exclude all audit services provided under U.S. EPA's RFS program from the high conflict of interest category. Staff further clarified in section 95503(c)(3) that audit services provided under U.S. EPA's RFS program do not pose a potential for conflict of interest and excluded them from categories of risk.
>
> In response to GROWTHENERGY3_SF31-6 and GROWTHENERGY3_SF31-16, while random compliance audits may be useful in some environmental regulatory programs, it does not meet the level of rigor needed to provide public confidence in market-based GHG programs. Random verification would not provide CARB with reasonable assurance that no material misstatement of data used to calculate LCFS credits or deficits has occurred. Work conducted by in-house teams and consultancies would not meet independence requirements nor provide reasonable assurance necessary for public confidence.

O-1.2. Multiple Comments: ***Specific Conflict of Interest Requirements***

Comment: We still believe some of the definitions of activities that trigger high conflict of interest are too vague and could benefit from revision. Below are some specific examples:

1. EcoEngineers offers a RIN tracking system to the biofuels industry that allows data transmittals from biofuel plants to the EPA for RIN generation purposes. The system acts as a "conduit" that transports producers' data directly from the producers' servers to EPA databases with no interference from EcoEngineers staff or agents. The system also stores it for future retrieval for record-keeping and auditing purposes. We do not believe this creates a high conflict scenario and it provides our auditors up-to-date information on fuel transaction and credit generation at the facility. Section §95503(b)(2)(A) currently offers an explicit exception to accounting software. We believe EcoEngineers' RIN platform deserves a similar exception.

2. In §95503(b)(2)(C), "Designing or providing consultative engineering or technical services in the development and construction of a fuel production facility; or energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit" is identified as triggering a high conflict. First, consultative engineering is a very broad phrase that is not clearly defined. For example, sometimes one of our engineers may be asked to provide an opinion on whether the LCFS requires the installation of a flow meter at a certain location to measure feedstock or finished fuel flows. We do not believe providing this opinion triggers a conflict of interest; however, the phrase "consultative engineering" can be interpreted to argue that it does. Second, the use of the word "development" in this context greatly broadens the scope of this conflict of interest and could include any task that ultimately helps a facility come into production. We believe that an engineer who is responsible for the design and construction of the facility should trigger a high conflict of interest; however, engineers also often provide independent, third-party opinions which ultimately assist projects make good decisions. These independent, third-party opinions should not be identified as triggering a high conflict of interest.

3. Section §95503(b)(2)(L) identifies "appraisal services of carbon or greenhouse gas liabilities or asset," as a service that triggers a high conflict and §95503(b)(2)(C) identifies "consultative engineering" as a service that triggers a high conflict. EcoEngineers sometimes provides its clients the current market value of renewable fuel credits as seen in 3rd party market transactions or other publicly available data such as CARB's website. This data may or may not be part of an independent economic analysis that compares potential future revenues with estimated capital and operating costs at a facility. It is our unbiased, independent opinion that creates value for our clients. We do not believe these services trigger a high conflict, and there should be some allowance for these types of relationships to continue without triggering a conflict.

Recommended Action:

1. Modify §95503(b)(2)(A) to include an exception for a data transfer system that exchanges RIN data between a facility and EPA databases.

2. Modify §95503(b)(2)(C) as follows: "Designing or providing engineering or technical services in the design and construction of a fuel production facility; or energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit."

3. Modify Section §95503(b)(2)(L) to allow for independent, third-party opinions of credit values or project costs and revenues to be a medium conflict with requirements that the report clearly identify the independence of the opinions within and/or a mitigation plan. (ECOENGINEERS3_SF22-3)

Comment: We have had discussions with many of our renewable fuel producer clients that have shown interest in acquiring services to assist in preparing them for LCFS verification implementation. These clients are volunteering to complete some of the major procedures pertaining to high-risk areas in the verification to ensure their processes and procedures are appropriate before implementation of the program. The original idea was to complete many of the verification data checks on 2019 data and to draft a mock corrections log and report to give the client an idea of where they may have issues. This would allow them to make corrections or changes to their processes and documentation prior to the actual implementation period.

Our firm would provide the client with the errors that we would be logging and reporting if the verification regulation was effective, but we would not be advising or consulting on corrective action plans. The corrections log maintained during this interim period would not be accessible to CARB. This would allow the entity to identify errors prior to the LCFS reporting period, making a smoother and more accurate implementation. It would also allow us as the verification body to test and adjust our verification procedures and start creating documentation and reports in anticipation of the effective date of the rule. We would also anticipate bringing questions to CARB and sending in mock reports so that CARB could see and approve our deliverables prior to implementation.

Currently, we have been made aware that any interim verification procedures completed on a voluntary basis would be considered a high conflict of interest item. We did realize that in completing procedures on 2019 data that we are working on a timeframe that would be covered by the first verification. We would like to suggest that at a minimum, we be allowed to complete verification procedures on 2018 data, which will never be included in a verification report to CARB. The renewable fuel producers are proactively preparing for this upcoming requirement and working hard to be in compliance, we strongly urge CARB to support these actions and allow review of 2018 data through limited verification procedures on a voluntary basis. (CHRISTIANSON2_SF10-4)

> **Agency Response:** Please see Response O-2.3 in Chapter IV regarding specific conflict of interest requirements.

O-1.3. Multiple Comments: ***Conflict of Interest Assessment for Grant Writing Assistance and Strategic Board Planning Services***

Comment: Christianson provides a grant writing service to a number of its clients including a large number of renewable fuel producers. The grant that we have been working on with most of our renewable fuel clients is the USDA Rural Energy for America Program (REAP). The REAP grant is to purchase, install or construct renewable energy systems, make energy efficiency improvements and to participate in energy audits. CARB members have told us that this service is considered a high conflict under section 95503 (b)(2)(C). We agree that we are providing a technical service (mainly technical writing services) for the construction of a fuel production facility or energy efficiency.

We would like CARB to understand how the grant writing process works. We at Christianson understand certain grant writing processes and documentation requirements. We help the renewable fuel producer complete the appropriate forms and accumulate, create and/or assemble the proper documentation required to be submitted with the grant.

In providing this service, we rely heavily on transparency in communication with the plant and require the producer to provide our team with all the relevant information and data that the application requires. Our expertise lies in writing the most impactful and complete application package to improve the likelihood of receiving funding. We do not advocate or lobby on behalf of our clients in discussions with any agencies and our compensation is not based on awards received.

In addition to these items, we do have separate teams that handle the grant writing services and the compliance verification programs (LCFS, RFS and Canadian Audits). Our verification services are handled by our accounting team who has extensive experience with auditing whereas our grant writing is handled by a separate team with very little accounting and auditing backgrounds, and strong backgrounds in research and technical writing. The qualifications for each of these two teams does not allow the work to be shared between departments in most instances.
(CHRISTIANSON2_SF10-1)

Comment: Christianson provides a benchmarking program to the ethanol industry where we collect data from a large number of plants, accumulate all the data, run key industry ratios and then make the data available to the participants in groups large enough so as not to identify any individual participant's data. This data is not used by the firm in audit or verification work. However, many participants of the benchmarking program have engaged Christianson to facilitate strategic planning meetings for their boards of directors. In these meetings, we pull certain data sets from the benchmarking system to present to the board for analysis and interpretation and to assist them in setting goals. Again, this service is presenting the plant's own data from our benchmarking program and facilitating the goal setting process with the board as well as follow up communications after the planning meeting to check on progress of their goals. We do not consult with the board or advise them on any direction the plant

should take or explore; we are simply there to keep the board on track with determining and setting goals.

We could not identify a specific high conflict section that this would violate other than our connection with the board of directors, which is not a relationship with any ownership or decision-making authority. Upon initial mention of this service, we were told it would be a high conflict. If CARB is aware of a high conflict item that this fits under, we would appreciate a wording adjustment to exclude this service because we are simply facilitators in a goal setting process. (CHRISTIANSON2_SF10-2)

> **Agency Response:** The purpose of the proposed COI provisions is to ensure that verification bodies and their staff would not be put in a situation to evaluate or contradict their own prior work for a particular client, as that could lead to lack of impartiality. Section 95503(b)(2)(C)) discusses making engineering or technical recommendations regarding project design, development, or construction intended to achieve GHG benefits. Activities provided for clients that do not include these services would not be considered high COI under section 95503(b)(2)(C). Evaluating the potential for COI from a particular prospective verification body's activities is beyond the scope of the Final Statement of Reasons and would need to be assessed as part of the verification body's disclosure during implementation of the Board-approved regulation. However, we invite Christianson to contact CARB staff directly to further discuss the potential COI in these instances.

P. Alternative Diesel Fuel Regulation

No comments were received on this topic during the 2nd 15-day comment period.

Q. Voluntary NOx Remediation Measure Funding and Draft Supplemental Disclosure Discussion of Oxides of Nitrogen Potentially Caused by the Low Carbon Fuel Standard Regulation

No comments were received on this topic during the 2nd 15-day comment period.

R. Economic Analysis

No comments were received on this topic during the 2nd 15-day comment period.

S. Environmental Analysis

S-1. Multiple Comments: *Comments on the Draft Environmental Analysis*

Comments: CAF2_SF14-1, CCAALACVAQ1_SF16-5, GROWTHENERGY3_SF31-5, GROWTHENERGY3_SF31-14b

> **Agency Response:** The responses to these comments are in "Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

T. Fuel Neutrality

No comments were received on this topic during the 2nd 15-day comment period.

U. Rulemaking Procedure

U-1. Multiple Comments: *Support for the LCFS Rulemaking Procedure*

Comment: DTEBE appreciates the work done by CARB in addressing many of our organization's comments in previous amendment packages. CARB has been diligent in assessing some of the key concerns voiced by DTEBE and other RNG producers. (DTEBE3_SF19-1)

Comment: In closing CARB staff should be commended in the overall work product that was produced under constrained conditions. This rulemaking has demonstrated CARB's leadership and commitment in greenhouse gas reductions while illuminating a path for which other jurisdictions can follow. (WE4_SF20-5)

Comment: We also appreciate the tremendous effort and accessibility of CARB staff during the extensive public process leading up to this hearing. (CALETC4_SF50-1)

Comment: We again thank CARB and the LCFS Program staff for the opportunity to comment on this critical rulemaking and for their effort, thoughtfulness, transparency and receptiveness to feedback through this process. Their work has produced a strong and set of proposals for the LCFS program and with a few amendments, as discussed in this letter, we are confident that the LCFS can achieve its full potential to deliver cleaner air, innovative technology and sustainable transportation. (NEXTGEN4_SF60-20)

Comment: We also appreciate CARB's commitment to interagency coordination. CPUC representatives have attended stakeholder meetings, engaged in multiple conversations with CARB staff throughout the regulatory process and provided informal feedback on the proposed regulation the past several months. Our feedback has focused on identifying any areas of the POP Proposal that may conflict with current CPUC decisions and suggesting modifications to facilitate the CPUC's smooth implementation of the new CARB rules to bring investor-owned utility (IOU) LCFS rebate programs into alignment with the new rules. As a result of the mutual coordination, we are pleased with the modifications that CARB staff made to the regulation addressing our comments. (CPUC1_SF64-2)

> **Agency Response:** Staff appreciates the commenters' support for the rulemaking process and staff's efforts.

V. Analysis of Alternatives

No comments were received on this topic during the 2nd 15-day comment period.

W. Miscellaneous

W-1. *Not Within Scope of Rulemaking*

W-1.1 *Suggestions for Promoting ZEV on Transportation Network Company Platforms*

Comment: Envoy is pleased that the Proposed Regulation Amendments include specific references to coordination with its sister agency, the California Public Utility

Commission (CPUC),[13] as the CPUC oversees Investor Owned Utility participation in the LCFS program, and Transportation Network Company (TNC) proceedings. To encourage innovative utilization of these funds, which may in turn lower costs while increasing benefits, Envoy encourages CARB/CPUC to leverage proceedings as a forum to further evaluate innovative LCFS funding approaches. This would seem to fit as a potential activity in alignment with Rulemaking 11-03-012, or as an emergent activity within the TNC rulemaking. Recommended topics of discussion in such rulemaking should focus on leveraging LCFS as an innovation accelerator, and should include, and not be limited to, the following:

[13] *PROPOSED SECOND 15-DAY MODIFICATIONS; Page 48. Website Access: https://www.arb.ca.gov/regact/2018/lcfs18/15dayatta2.pdf.*

- Investments focused on accelerating EV adoption in TNCs, such as high-mileage fleets incentives;[14]

  [14] For example, Lyft is seeking to implement an innovative approach to increase the value of LCFS investments by investing in program activities that maximize EV utilization by targeting high-mileage fleets. See: Lyft Comments; RE: Proposed amendments to the low carbon fuel standard regulation and to the regulation on commercialization of alternative diesel fuels – April 27, 2018 Hearing; Website Access: https://www.arb.ca.gov/lists/com-attach/241-lcfs18-BzUFM1NjWTIAKAk5.pdf

- Pilot program concept proposals from EDUs, TNCs, and other related stakeholders;
- Investments in mobility options, mobility hubs, and one-stop-shops;
- Infrastructure investments, including collaborative opportunities with the Affordable Housing and Sustainable Communities and Transformative Climate Communities Programs;
- Customer awareness activities, including marketing, education, & outreach; and
- Others.

While this rulemaking has been successful, there remain expanded opportunities to develop innovative pilot and program activities and unique use cases for LCFS credits. As such, Envoy encourages CARB/CPUC to work with stakeholders to integrate an LCFS innovation topic into any emergent CPUC rulemaking. (ENVOY2_SF55-7)

Agency Response: Please see Response D-6.1j in Chapter V.

W-1.2.Comment: Page 32: Section 95482 exempts non-biomass-based fuels that are "supplied in California at an aggregated quantity of less than 420 million MJ (3.6 million gasoline gallon equivalent) per year" from LCFS requirements. The exemption should apply to all fuels including biomass-based fuels so as not to discourage the production and use of biomass-based fuels in the state. (TASKFORCE3_SF8-2)

> **Agency Response:** Staff appreciates the commenter's suggestion but notes that this recommendation is not within the scope of this rulemaking because the modifications discussed in the comment were not incorporated in the proposed revisions or included in the notice of changes.
>
> Nonetheless, staff would refer the commenter to the original rationale for this exemption, as stated in staff's 2009 ISOR:[65]
>
>> "The exemption is intended to allow alternative fuel providers, particularly small volume producers whose fuels have inherently low carbon intensities, adequate lead time to develop the technologies necessary to make their fuels viable for future transportation applications.
>>
>> Not all alternative fuels, however, qualify for the low volume exemption. Biomass-based fuels, such as denatured fuel ethanol and biomass-based diesel, and fuel blends containing biomass-based fuels, do not qualify for the exemption regardless of the quantity produced due to the potential land-use impacts and other global sustainability and economic considerations of biofuels."

W-1.3.Comment: As indicated in our previous communications, the Task Force strongly believes that the State and/or CARB should implement measures incentivizing funding (grants, low interest loans, tax reductions, etc.) to develop infrastructure, such as waste processing facilities and biomethane pipelines, that is needed to produce low-carbon intensity (CI) fuels to comply with the LCFS regulations as well as to meet the organic waste disposal reduction targets of Senate Bill 1383. The availability of such infrastructure is crucial to achieve the 2020 and 2025 organic waste disposal reduction targets of 50 percent and 75 percent, respectively. The 88 cities in Los Angeles County and the County unincorporated communities currently have a maximum organic waste composting and AD processing capacity of approximately 0.5 million tons per year and approximately 1.3 million tons per year of chipping and grinding capacity. Additionally, it is estimated that jurisdictions in Los Angeles County also dispose over 3.5 million tons per year of organic waste. Additional composting and especially AD infrastructure, at an estimated cost of over one billion dollars, is needed to address this capacity shortfall. The Task Force also believes that some funding assistance from Cap and Trade should be made available to jurisdictions for the construction and operation of the needed facilities.

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[65] Staff Report: Initial Statement of Reasons: Proposed Regulation to Implement the Low Carbon Fuel Standard." March 5 (2009). https://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor1.pdf

This funding for waste processing facilities should not be limited to AD and composting facilities only and should also include non-combustion thermal conversion technologies (CTs). These facilities can produce low-CI fuels and reduce emissions of methane and other greenhouse gases (GHGs) by processing recyclable materials and thus, avoid potential landfill disposal of recyclable materials due to China's National Sword Policy. (TASKFORCE3_SF8-3b)

> **Agency Response:** Please refer to Response W-4 in Chapter IV and specifically to the response for TASKFORCE1_89-3 in that section.

W-1.4.*Cost Containment Mechanism and Floor Price*

Comment: This comment may not be achievable during this rulemaking, but HZI would like to urge staff to explore provisions for establishing a floor price for LCFS credit value, such that industry stakeholders can have the confidence necessary to invest in renewable fuels in California. (HZI1_SF12-7)

> **Agency Response:** Please refer to Response W-4 in Chapter IV in response to comment EIN1_B11-3.

W-1.5.*Implementation*

Comment: Given the changes proposed in this rulemaking cycle to the electricity portion of the LCFS program, ChargePoint recommends that ARB develop a streamlined data collection system. With thousands of chargers currently registered in the program, as well as a proposed Time-of-Use (TOU) program that would require hourly data reporting, the current system of emailing Excel files as back-up verification data is neither secure nor efficient. Additionally, we recommend creating a calculator, similar to The LCFS Credit Price Calculator[iii], which would allow an FSE to estimate credit generation via the various credit generation opportunities being solidified in this current rulemaking.

[iii] https://www.arb.ca.gov/fuels/lcfs/dashboard/creditpricecalculator.xlsx

(CHARGEPOINT4_SF32-7)

> **Agency Response:** Please see Response W-3, LCFS Implementation, in Chapter IV.

W-1.6.Comment: i, we herebyincorporate by reference all history of my /our communications with us and the scd bad carb both oral and written etc and last and this years litigation with scd and carb on the 2016 scd plan which carb and the dist approved. this includes the entire record of he pspc for all past planas includding decades of backsliding 86 ing solar air pollution for over 40 years of dist plans wh with us .

This includes the bc cases filed in june and july 1992 and asw welll our january 1981 case filed aqgainswt the cpucs final decsion in oii 42 which zwas for --- ive been ourged and cut off several times while weitting this so 8imndont want to get cut oof or nnot

include theswe comments so ill submit this and send another asap etc (EDER1_SF41-1)

> **Agency Response:** The commenter asks that various undefined collections of documents be incorporated either into the comment or into the administrative record – it is not clear which. It is unclear what documents the commenter wants included. From the vague descriptions, the documents do not appear to relate to the current rulemaking.

W-1.7.Comment: also the sate health and saFETY CODE 53002 B MAKES THE 90 PERCENT GAS USED IMPORTED INTO CA IS ILLEGAQL SINEC 1981 AND WAS PURGED IE NOY EVERY PRINTED IN THE4 BLUE BOOK CALIFORNIAS AIR POLLUTION CONTROLK LAWS

YOUR N GASW LCFS AND OTHER C ANDS I ANDS RWES IN CQA IS ALL ILLEGAL

AND SO CALL3ED RENEWABLE N DEIRTY TI TOXIC GAS SPREAQDS DRUG RESISTANT ANTI BIOTICSW VIA THE CA GAS PIPELINE DIST SYSTEM 10 ANSD 100S OT THOUSANDSDAW DIE E3SWCH YR FROM THIS ANDE YOU FOLDS SSUBSADIZE THIS. . . . (EDER1_SF47-2)

> **Agency Response:** This comment does not appear to relate to the current rulemaking. The commenter asserts that 90 percent of gas used in California is imported, making it illegal pursuant to Health & Safety Code section 53002, subd. (b). Assuming that the commenter refers to natural gas or renewable natural gas, importing such fuels is, in fact, legal. In the cited statute, the Legislature merely "declares its intention that the provisions of this part [pertaining to financing solar energy and energy conservation] be interpreted and implemented" so as to help "reduce the dependence of California on imported and nonrenewable energy sources, as well as to hold down increases in the cost of energy."
>
> The comment then claims that renewable gas is "toxic" and "sprea[]ds drug resistant anti biotics[] via the CA gas pipeline … an[]d 100s o[f] thousand[]d[s] die e[a]ch yr from this …". No evidence or reputable study is cited to support that claim, and despite CARB staff's knowledge and literature review regarding renewable natural gas, CARB is not aware of any such evidence or study.

W-1.8.Comment: ch4 has increased over 30 per cent ocer the past 12 years as cited in the scd 2-16 plan in chapter 10 page 2 and 3 written by arron katzenstein who was taken w away from working with me us 2 years ago and is now incharge of the dist labs also dr, kaqTZENSTEIN DID HIS DR DISSERTATION ON METHANE CH4 .. THATS WHER NOBELS IN CHEMISTRY WHENT TO CHEMISTS REVEALING THE HOLE IN THE OZONE LAYER ANSD ITS MAN HUMAN MADE STOFFSTUFF

ALSO SEE MY OUR COYRIGHTEDE RESPOONCE TO THIS AFTER MUCH DISCUSWSION WITH DR, K INC BY REF MY OUR AUGUST 12,2016 COMMENTS ON THIS ANSD THE PLAN ANXDD THEIR IE THE DIST ANDE CARB COMPLETEO

OMISSION OF AND TECHNICAL RESPONCE TO THIS NE3W FACT ETC AND OTHER VARIABLES ETC'

CARB NOW USES ABOUT 459 PPMCO2E OR EQIUIVILENT ANDS REAL NUMBERS ARRRRE FROM 80 PERCENT TO 100 PERCENT HIGHER NOWW NOW 205 0 OR 2100 ETC (EDER2_SF62-1)

> **Agency Response:** The commenter notes that methane "has increased over 30 percent o[v]er the past 12 years." This comment does not appear to relate to the current rulemaking.

W-1.9.Comment: PLEASE G3ET ME INSIDE THE GOVS G;OB;A CLIMATE CONFERENCE .. ANDS INC BY REF IS ARE ALL OF MY WI WRITTEN AND ORAL COMMUNICAQT5IONS AND AOR CONTACT 9INCLUDING CPUC VBIOLATING MY OUR RIGHTS ETC AS AN THE FIRST ENVIRONMENTAL JUSTICER FOLK BEFOR THE TER4M WAS EVER USED AND CALLED AN FBI AQGENT BY TOM HAYDEN GOV BROWWNS POINT MAN 78 TO 82 HEAD OF AOLr cal solar cal whentelling organizers ffffffffof the first national anti nuc power pro solar renewables to the easters organizers of d.c. that he didn't come tto the meeting because i harvey eder was an fbi agent this is deep shit process gov b get me into your global climate conf sir if you are rrrrightous to any extent5 process ej etc justice all the record is in the record and incorporate this and all other comments ever tto the state of ca other states fe3deral entities an internationallllllMWERIGAN SOLAR ENRERGY SOCIETY INT SOLAER ENERGY SOCIETY ETYC THE I 1SWT NATIONAL ANTI NUC POWEER PRO SOLAR RENEWS WAS HEALD IN AUGUST 1978 1 WEEK AFTER THE CALIF ABLONE QABALONE ALLLIANCDEHAD 500 FOLKS ARRESTED AT DIABLOCANYON NUCLEAR CCPOEPOWER PLANT IN SLO...I WAA THE CONSESSUS CHOSEN REP MONTHS BEFORE ME MTING AT THE uNIOVERSITY OF kentucky Louisville..both hayd--- also the book we publisjhed of the meeting purged california ansd much of the west including the west coast... greaatful de3ad their aint no time to hate/ b either anit or barely teens etc and brownsw .....bad aqctiond 40 yrsw ago wed be4 way on the way to or at local state nat ansd int nat solar conversion v. almost up the cr4eek without a paddle...this new left bws has been extremely costly--- also the book we publisjhed of the meeting purged california ansd much of the west including the west coast... greaatful de3ad their aint no time to hate/ b either anit or barely time to waittt.....neal young the real...this stuff is cited in the current litigation transcript.... ALSO AUTHOR OF THE APX 50 ITEM SOLAR NEW3 DEAL SUBMIITTED IN 2016 AND 2017 ETC... ALSO IOINCORPORATE BY REFERENCE 10 PULS YEARS AGO COMMUNICATIONS WEITH JOHN CPOURTES AND ANEEL IS ALL IN THE RECORD ,, ITHIIWSTHIS INCLUDES THE LACK OF REAL WORLD EMISSIONS FROMALL WAYS OF THE ENGINE AND THE TRANSPORT SYSTEMS.. WHICH WAS IS HAS NEVEEER BEEN STUDIE4S , ALSO HAD VOCONVERDSATRIONS WITH dRR. lINDA sMITH WHOO AGRE4ES THAT A STUDYT NE3EDS TI B E DI DONE ON PRE MATURE DEATHS PEER MILLION FROM CH4 METHANE (NOW 86 GWP IS USED BY IPCC CALIF TOO HUH G USING WASTE FROM SEWERSS LANDFILLLD ANED FEED LOTS OVER 7-

7 PERCENT OF HUME3N ANTI BIOTICS GO TO CATTRLE G FEED IT WAS NOT REQUIRED TO REPORT DE3ATHS FROM DRUG RESISTANT AQNTI BIOTICS UNTIL THE DFIRST OF THIS YER..

SORRY ABOUT MY TYPING I HAD EMERG4EMCY SUR4GERY ON MY HANDESW YRWS AAGO COLOR OF AUTHORITY ETC

THIS IS PART 2 OF AR 4 21 PM 8 30 M18 HARVEY EDER SELF ANSD FOR PSPC ANS THIS AND IHNC BY REF ALL OF THE GOVS GLOBAL CLIMATE CONFERENCE WOONT LET ME US IN CAUSE I WWE ARE THE PROGRESSIVES (EDER2_SF62-2)

> **Agency Response:** This comment does not appear to relate to the current rulemaking.

W-1.10. Comment: Your applicant fyll name Boketsu with my spouse name Mengi mulandu esperance ask partners If I can to received employment and to join the distinguished groups students at UC san diego/dpt of economics tel;+18585342230 and arrival before august 30,2018. (BONALD1_SF9-1)

> **Agency Response:** This comment does not appear to relate to the current rulemaking.

VII. SUMMARY OF COMMENTS MADE DURING THE SECOND BOARD HEARING

Chapter VII of this FSOR contains all comments submitted during the second CARB Board Hearing on September 27, 2018, with CARB's responses.

CARB received 8 comment letters during the Board Hearing. In addition, 42 stakeholders gave oral testimony. Each comment letter and the transcript of the testimony are responded to in this chapter. Table VII-1 below lists the commenters that submitted oral and written comments on the proposed amendments during the second Board Hearing, identifies the date and form of their comments, and shows the abbreviation assigned to each.

The individually submitted comment letters for the 45-day, first 15-day, and second 15-day comment periods are available here: https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm

Note that some comments were scanned or otherwise electronically transferred, so they may include minor typographical errors or formatting that is not consistent with the originally submitted comments. However, all content reflects the submitted comments. All originally submitted comments are available here: https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm. Transcripts for any verbal testimony presented during the first Board Hearing is available here: https://www.arb.ca.gov/board/mt/2018/mt042718.pdf?_ga=2.118956489.1942328084.1531756299-1243162238.1525361489

Comments that address the draft Environmental Analysis are responded to in the "Supplemental Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuels Regulations."

A. List of Commenters

Listed below are the organizations and individuals that provided comments during the first 15-day comment period:

Table VII-1. List of Commenters During the Second Board Hearing

Comment Letter Code	Commenter
SB_NRDC6_SB1	Jeffrey Bobeck, Center for Climate and Energy Solutions Deepika Nagabhushan, Clean Air Task Force Timothy O'Connor, Environmental Defense Fund George Peridas, Natural Resources Defense Council Board Hearing Comment: September 27, 2018
SB_OCCIDENTAL7_SB2	Miles Culhane, Occidental Petroleum Board Hearing Comment: September 27, 2018
SB_CAF5_SB3	Patrick J. McDuff, California Fueling Board Hearing Comment: September 27, 2018

SB_CATF5_SB4	Deepika Nagabushan, Clean Air Task Force Board Hearing Comment: September 27, 2018
SB_NEXTGEN6_SB5	Colin Murphy Ph.D., NextGen California Board Hearing Comment: September 27, 2018
SB_UNICA6_SB6	Leticia Phillips, Brazilian Sugarcane Industry Association (UNICA) Board Hearing Comment: September 27, 2018
SB_WORLD2_SB7	Erin Donnette, World Energy Board Hearing Comment: September 27, 2018
SB_GROWTHENERGY4_SB8	John P. Kinsey, Wanger Jones Helsley PC on behalf of Growth Energy Board Hearing Comment: September 27, 2018
ST_OREGON1_ST00	Leah Feldon, Oregon Department Environmental Quality Oral Testimony: September 27, 2018
ST_UTILITYAUTO1_ST0	Steve Douglas, Alliance of Automobile Manufacturers Eileen Tutt, CalETC Oral Testimony: September 27, 2018
ST_REG5_ST1	Scott Hedderich, Renewable Energy Group Oral Testimony: September 27, 2018
ST_ZEVI1_ST2	Tyson Eckerle, ZEV Infrastructure Oral Testimony: September 27, 2018
ST_WORLD1_ST3	Erin Donnette, World Energy Oral Testimony: September 27, 2018
ST_PERFA1_ST4	Neil Koehler, Pacific Ethanol and RFA Oral Testimony: September 27, 2018
ST_NBB1_ST5	Shelby Neal, National Biodiesel Board Oral Testimony: September 27, 2018
ST_CRC2_ST6	Brian Pellens, California Resources Corporation Oral Testimony: September 27, 2018
ST_ALA1_ST7	Will Barrett, American Lung Association Oral Testimony: September 27, 2018
ST_NRDC4_ST8	George Peridas, NRDC Oral Testimony: September 27, 2018
ST_CATF4_ST9	Deepika Nagabushan, Clean Air Task Force Oral Testimony: September 27, 2018
ST_CRF3_ST10	Norm Ueanten, Crimson Renewable Oral Testimony: September 27, 2018
ST_CHARGEPOINT5_ST11	Amanda Myers, ChargePoint Oral Testimony: September 27, 2018
ST_CRC3_ST12	Maris Densmore, California Resources Corporation Oral Testimony: September 27, 2018
ST_WE5_ST13	Kim Do, White Energy, Inc. Oral Testimony: September 27, 2018
ST_OCCIDENTAL6_ST14	Myles Culhane, Occidental Petroleum Oral Testimony: September 27, 2018

ST_CONESTOGA3_ST15	Tony Brunello, Conestoga Energy Partners Oral Testimony: September 27, 2018
ST_EDF2_ST16	Katelyn Roedner Sutter, Environmental Defense Fund Oral Testimony: September 27, 2018
ST_CAF4_ST17	Pat McDuff, California Fueling Oral Testimony: September 27, 2018
ST_WSPA10_ST18	Tom Umenhofer, Western States Petroleum Association Oral Testimony: September 27, 2018
ST_AJFP5_ST19a	Graham Noyes, Noyes Law Corporation on behalf of Alternative Jet Fuel Producers Oral Testimony: September 27, 2018
ST_LCFC2_ST19b	Graham Noyes, Noyes Law Corporation on behalf of Low Carbon Fuels Coalition Oral Testimony: September 27, 2018
ST_CCA3_ST20	Rocky Rushing, Coalition for Clean Air Oral Testimony: September 27, 2018
ST_RNGC4_ST21	Nina Kapoor, Coalition for Renewable Natural Gas Oral Testimony: September 27, 2018
ST_CABA1_ST22	Rebecca Baskins, California Advanced Biofuels Alliance Oral Testimony: September 27, 2018
ST_ANDEAVOR3_ST23	Brian McDonald, Andeavor Oral Testimony: September 27, 2018
ST_NRDC5_ST24	Nikita Koraddi on behalf of Simon Mui, Natural Resources Defense Council Oral Testimony: September 27, 2018
ST_BAC3_ST25	Julia Levin, Bioenergy Association of California Oral Testimony: September 27, 2018
ST_UNICA5_ST26	Leticia Phillips, Brazilian Sugarcane Industry Association (UNICA) Oral Testimony: September 27, 2018
ST_NEXTGEN5_ST27	Colin Murphy, Next Generation California Oral Testimony: September 27, 2018
ST_CE6_ST28	Todd Campbell, Clean Energy Oral Testimony: September 27, 2018
ST_TESLA3_ST29	Fei Chi, Tesla Oral Testimony: September 27, 2018
ST_UCS5_ST30	Jason Barbose, Union of Concerned Scientists Oral Testimony: September 27, 2018
ST_EE1_ST31	Andy Wunder, Environmental Entrepreneurs Oral Testimony: September 27, 2018
ST_CALSTART4_ST32	Ryan Schuchard, CALSTART Oral Testimony: September 27, 2018
ST_CHBC3_ST33	Emanuel Wagner, California Hydrogen Business Council Oral Testimony: September 27, 2018

ST_H2IND5_ST34	Tim Brown, FirstElement Fuel and Hydrogen Industry Robert Bienenfeld, Honda Bud Beebe and Emanuel Wagner, California Hydrogen Business Council Wayne Leighty, Shell Hydrogen Shane Stephens, FirstElement Fuel Mike Lord, Toyota Oral Testimony: September 27, 2018
ST_GLASSPOINT3_ST35	John O'Donnell, GlassPoint Oral Testimony: September 27, 2018
ST_GA1_ST36	Julia Rege, Global Automakers Oral Testimony: September 27, 2018
ST_UNITED2_ST37	Kathleen VanOsten, United Airlines Oral Testimony: September 27, 2018
ST_SCG5_ST38	Kevin Maggay, SoCalGas Oral Testimony: September 27, 2018
ST_AJW1_ST39	Christopher Hessler, AJW, Inc. Oral Testimony: September 27, 2018
ST_CNGVC5_ST40	Thomas Lawson, California Natural Gas Vehicle Coalition Oral Testimony: September 27, 2018

B. General Comments in Support of the Proposed Amendments

B-1. Multiple Comments: *General Support for the Proposed Amendments*

Comment: Occidental Petroleum supports the Air Resources Board's adoption of the proposed amendments to the Low Carbon Fuel Standard… (OCCIDENTAL7_SB2-1)

Comment: Occidental strongly supports the amendments to the Low Carbon Fuel Standard… (OCCIDENTAL6_ST14-1)

Comment: We have been strong supporters of the LCFS over the last several years and look forward to building upon its success over the decades to come.

The production and consumption of transportation fuels accounts for over 40% of California's total GHG emissions. California cannot meet its long term climate and clean air goals, including those specified in SB 32 and Executive Order B-55-18 without significant reductions from this sector. The LCFS plays a critical role in facilitating the kinds of transformative change which will be necessary over the coming decades. It is therefore crucial that the LCFS achieve the fullest extent of its potential to drive down emissions and support advanced clean energy technologies.

…

CARB has an opportunity to build upon many years of success by extending a strong LCFS program through 2030 and building upon the foundation it has laid. California has

an opportunity to continue its leadership in climate, clean energy and transportation policy for years to come. (NEXTGEN6_SB5-2)

Comment: We've been a very strong supporter of the LCFS for many years. Now, we think it's a critical and often underappreciated part of California's climate portfolio. And I look forward to being a strong supporter of the LCFS for many years. We definitely support readoption of the package that's before you. For the most part, it reflects a lot of very strong improvements over the span of the last year through the workshopping in process. (NEXTGEN5_ST27-2)

Comment:

- *These environmental programs provide the correct market incentives for our company to thrive.*
- *As a result, we are creating jobs for Californians producing clean, renewable energy.*
- *The renewable diesel and jet fuel products from our process reduce lifecycle greenhouse gas emissions by at least 60% compared to similar petroleum-based products.*
- *Additionally, they eliminate carcinogenic pollutants like benzene and xylene.*

…

- *Furthermore, we believe the success of renewable diesel and jet fuels in California can contribute powerfully to the case for expanding the LCFS more rapidly to other parts of the country – and accelerating the opportunity for others to follow the path blazed by CARB and California.* (WORLD2_SB7-3)

Comment: With respect to your current rulemaking, Oregon strongly supports the proposed changes to your program: In particular, the extension of the program's goals to 20 percent by 2030; the updates to the GREET Model; the inclusion of the third-party verification; and the addition of renewal jet fuel as a source of credits. (OREGON1_ST00-1)

Comment: We support the LCFS and your adoption of the program amendments being proposed today. (PERFA1_ST4-2)

Comment: We are thrilled with the LCFS, very supportive of this package. We view ourselves as one of the many success stories from the Low Carbon Fuel Standard. Our volumes in the state have increased from 14 million gallons when the program began to more than half of a billion last year. And according to modeling, we'll around a billion in 2020.

In addition to the climate benefits, we also have shown economic benefits. There are eight biodiesel plants in the -- in the state now, one renewable diesel plant. Those are

geographically disbursed from as far south as San Diego and Coachella to as far north as Lake Tahoe.

So we are all over the state creating jobs, and that is, in short, from the low-carbon stand. When we're asked what can be done to continue to succeed, the answer is regulatory certainty. The reason we're so supportive of this package is because it does that. It gives us certainty through 2030 in conjunction with the ADF provisions, as well as the carbon intensity benchmarks and carbon intensity modeling through GREET, which is extremely accurate. That sounds easy to do, but it's very hard to do. (NBB1_ST5-1)

Comment: Base on the growth and demand generated by the LCFS, we recently broke ground on a plant expansion that will increase our production by 50 percent. Our Bakersfield biodiesel plant would not exist if the LCFS had not created the demand for cleaner burning low and ultra low carbon fuels.

I am proud to say that the biodiesel crimson produced in 2017 generated carbon savings equivalent to removing 49,000 cars off the road of California.

As we look to a future where LCFS is moving California to a 20 percent carbon reduction in its transportation fuel sector by 2030, we believe biofuels will continue to play a critical role in achieving these carbon reductions. And we anticipate continued investment by Crimson and many others in attendance at this Board meeting. (CRF3_ST10-2)

Comment: I'm here to voice support for the LCFS, as well as the inclusion of the CCS protocol… (WE5_ST13-1)

Comment: The two things, that we'd like to support the LCFS program… (CONESTOGA3_ST15-2)

Comment: EDF has been working on this and other climate policies in California for many years. And in 2015, we co-published a study quantifying the benefits of the LCFS and the cap-and-trade programs. The results of that study hold true today. By transitioning the state's transportation system to cleaner fuels and a more diverse vehicle fleet, these programs will result in cumulative savings of over $10 billion by 2020 and over 23 billion by 2025. These savings are in greater energy security, decreasing climate pollution, and decreasing local pollution that harms public health.

It's an essential component of the shift away from fossil fuel consumption. (EDF2_ST16-1)

Comment: With that being said, I'm pleased to offer our comments and support of this key climate policy. Extension of the LCFS is an important part of California meeting its emission targets and improving our air quality for all residents. (EDF2_ST16-5)

Comment: CCA supports the adoption of the 2030 Low Carbon Fuel Standard. (CCA3_ST20-1)

Comment: That being said, we're pleased to support the package before you today and look forward to continuing to partner with you in decarbonizing transportation in California. (RNGC4_ST21-4)

Comment: As a result of the Low Carbon Fuel Standard, we have multiple in-state facilities producing tens of millions of gallons of a renewable low carbon diesel replacement that is contributing to California's climate change goals each and every day.

Along with these environmental benefits, these facilities provide jobs and economic benefit to their communities in the state. With the National Biodiesel Board, we have worked closely with your staff on these amendments before you.

We thank you for your work on this, and we respectfully ask for your support. (CABA1_ST22-1)

Comment: Not two weeks after hosting the GCAS, California is again demonstrating bold leadership by strengthen and extending the LCFS to 2030.

From its inception 10 years ago, the LCFS has now grown to become one of the state's heavy weight climate fighters knocking out 40 million metric tons of climate pollution to date, and increasing the use of clean fuels in the State by 74 percent.

I want to provide NRDC's support for many of the newer modified clean fuel pathways under the program. This includes the creation of pathways for aviation biofuels and the pathways to replace high carbon process energy used in the petroleum industry with renewables like biogas and solar thermal.

As our planet warms, as droughts and wildfires become more common and affect the health and security of so many of our communities, we'll need the entire array of climate fighting technologies at our disposal. (NRDC5_ST24-1b)

Comment: I wanted to start by recognizing your leadership in this program and the very hard work of Sam and his entire team.

We have historically supported the Low Carbon Fuel Standard, and we continue to do so.

…

I just wanted to conclude by saying that we understand and we support CARB's desire to enhance the program. We have, as I said, historically supported it. And our comments today are really to ensure that more sugar cane ethanol will reach California tanks and ports.

With that said, thank you again for your leadership and for all the hard work towards this program. (UNICA5_ST26-1)

Comment: It's been a long time since we've been working together on the Low Carbon Fuel Standard. It's one of my favorite rules, and I think it does a lot of good, and you're showing tremendous leadership, not just here but in many other venues. And I'm very happy to see that Oregon was here tonight, because we work with Oregon too, and we'd like to add places like New York, and Washington, and other venues. (CE6_ST28-1)

Comment: Despite the challenge that the State has had thus far, really bending the curve on transportation emissions, the Low Carbon Fuel Standard is the policy that gives me hope that we will succeed on that endeavor. And that's because from day one this policy has succeeded in increasing the use of alternative fuels in the state. It's provided a clear market signal to producers to shift to the lowest carbon feed stocks, and production processes.

And so in sum, the program has been a resounding success. And the amendments that you are voting on shortly will be a big step forward setting up the program well to grow in ambition over the next 12 years. So this marathon hearing has not been quite as flashy as a bill signing, but your vote tonight is a very big deal, and so congratulations to staff and board for a job well done. (UCS5_ST30-1)

Comment: I'm here on behalf of E2's 600 California members to show strong business support for the staff's proposal to strengthen and extend the Low Carbon Fuel Standard through 2030. We strongly support the current proposal being voted on today as very achievable. (EE1_ST31-2)

Comment: Since 2011, $2.8 billion have been invested in clean fuel production in California. And this investment in low carbon fuels generates jobs. More than 300 companies with more than 20,000 workers across California working in the clean transportation technology industry. And by diversifying us away from petroleum, the Low Carbon Fuel Standard saves California families money at the pump.

This economic success story well be significantly advanced under the proposed extension being considered today. (EE1_ST31-4)

Comment: And on behalf of my members, I want to offer our support for the Low Carbon Fuel Standard program. We have and continue to be strong supporters and want to see this program succeed.

We, you know, are excited with the engagement that you heard today from folks in the biofuels industry, biodeals and renewable natural gas and others that were here to share why this program is important, and we believe in their comments as well. I did want to say that, you know, I know that we're not going to get into all of it tonight, and we look forward. Our members, we represent fuel providers, OEMs, utilities stand ready to assist and engage with staff moving forward.

We appreciate all their support on some of the earlier things that we discussed, and we look forward to continuing to engage, and we just want to thank you for your time, and as it's been said, and I'll be the last one to say it, your endurance. (CNGVC5_ST40-1)

Agency Response: Staff appreciates the commenters' support for the LCFS and the specific modifications to the proposed amendments described in the comments above.

B-2. Multiple Comments: ***Approve the Amendments to the Low Carbon Fuel Standard***

Comment: In closing, Occidental urges this board to adopt … the proposed amendments to the LCFS… (OCCIDENTAL7_SB2-7)

Comment: NextGen California strongly supports voting to adopt the proposed amendments… (NEXTGEN6_SB5-1)

Comment: This is really a critical time in the ZEV market we chose the -- kind of the puzzle piece theme of the presentation, because the pieces are coming together, but we have a long way to go, if we're going to meet the goals of the legislature, the Governor, and this Board, and the State of California.

So it's really important that we act. It's important that we cat act now, and that's what we're asking you to do to approve the proposal.

…

And we still have a lot of work to do. We can't do anything -- any of that work until the Board approves this, so we ask you to approve it now. And we're committed to working together and expanding our stakeholder group as we move forward.

…

This slide just gives you an idea of the timeline. And as Steve said, you can see from the ZEV adoption curve, that this is an absolutely critical time. We really need you to adopt this regulation today. (UTILITYAUTO1_ST0-2)

Comment: And I hope that quickly, whether it's tonight or tomorrow, it's adopted, because it's the right thing to do. (REG5_ST1-3)

Comment: We applaud CARB's commitment to the LCFS, and encourage the program's re-adoption. (WORLD2_SB7-1, WORLD1_ST3-1)

Comment: And we urge you respectfully to adopt this as soon as possible. 7:00 o'clock would be ideal. (NBB1_ST5-3)

Comment: With that, I'd like to thank you and I urge the Board to provide an aye vote and keep the LCFS climate-fighting champion going strong until 2030. (NRDC5_ST24-4)

Comment: And it is because of these climate, public health, and economic reasons E2 requests the Board votes yes on staff's proposal to strengthen and extend the Low Carbon Fuel Standard as proposed. (EE1_ST31-5)

> **Agency Response:** Staff appreciates the commenters' support for the Board to approve the amendments to the Low Carbon Fuel Standard.

C. Definitions

No comments were received on this topic during the 2nd Board Hearing.

D. Fuels Subject to the Regulation

D-1. *Alternative Jet Fuel*

D-1.1. Multiple Comments: *Support for the Proposed Alternative Jet Fuel Provisions in the Low Carbon Fuel Standard*

Comment:

- We are especially grateful for the hard work by staff on the inclusion of aviation fuels as an opt-in fuel.
- The lower emissions of renewable jet fuel is helpful to lower socio-economic communities that are often located near airports, as most emissions happen at takeoff and landing. (WORLD2_SB7-2)

Comment: We're also especially grateful to the -- from the -- sorry for the hard work of the staff on the inclusion of aviation fuels as an opt-in fuel. (WORLD1_ST3-2)

Comment: First one is Noyes Law Corporation on behalf of the alternative jet fuel producers. That's World Energy Paramount, Neste, Velocys, Red Rock, Gevo, and Fulcrum. We stand in strong support of the proposal here, appreciate all the great work that staff has done with us. No caveats, no requests. (AJFP5_ST19a-1)

Comment: We're thrilled that we were able to be included in this round of amendments.

United Airlines, some of you may have heard last week in San Francisco, we did a couple major things. One, we launched the first international flight using alternative jet fuel. That was the longest transatlantic flight so far to date. So we're very excited about that.

This follows on the heels of two years ago a launch at LAX, which the Assemblyman -- or Assemblyman Hector De La Torre was at. We appreciate that. And Sam joined us at the event last Friday.

Another major announcement that United has made is that they have committed to reducing their greenhouse gas emissions by 50 percent by 2050. Obviously, alternative jet fuel is a foundation, it's a cornerstone, of that effort. It's the biggest possible savings that we can get. So we thank you, thank -- I want to thank your staff obviously, Sam Wade and his team. We had some wonderful discussions on the science. We got the carbon intensity baseline correct. So we're thrilled with the proposed amendment as they are, and encourage your support. (UNITED2_ST37-1)

> **Agency Response:** Staff appreciates the support for including alternative jet fuel in the LCFS program as an opt-in credit-generating fuel, including the specific modifications described in the comments above.

D-2. ***Propane***

No comments were received on this topic during the 2nd Board Hearing.

D-3. ***Fossil Compressed Natural Gas***

D-3.1. ***Support for the Proposed Amendments to the Fossil Compressed Natural Gas Provisions***

D-3.1a. ***Support for the Exemption and Phase-In Period for Removal of Opt-In Status for Small Station Dispensing Fossil CNG***

Comment: We are pleased the exemption for fossil CNGs. There's 150,000 gas gallon equivalent or less. This will help in protecting small users of fossil CNG until they can ultimately be moved to renewable gas. (SCG5_ST38-2)

> **Agency Response:** Staff appreciates commenter's support for the proposed exemption and believes the proposed change would provide small CNG station owners the flexibility to defer opting in if they choose so in order to better plan their participation in the LCFS program.

D-3.2. ***Exemption and Phase-In Period for Removal of Opt-In Status for Small Station Dispensing Fossil CNG***

D-3.2a. Comment: While we are pleased with the exemption, we would still like to see delayed implementation of the mandatory reporting for all fossil CNG users as it will remain a credit generating fuel until 2024.

Mandatory reporting in 2019 would be five years prior to becoming a deficit fuel. In contrast, propane users are required to report two years prior to becoming a deficit fuel. We just want the same -- we just want CNG to be treated the same.

We understand that this change isn't going to happen today, but we do want to keep this issue in front of the Board and staff so it can be included in any future revisions. (SCG5_ST38-3)

> **Agency Response:** Please see Response D-3.2 in Chapter V.

D-3.2b. Comment: We also want to offer our help with the program. As a natural gas utility, we have capabilities, such as data collection and outreach that would greatly benefit the program. We surveyed transportation CNG users who have not opted into the program yet. And we found that about two-thirds of the folks that we -- that responded, either didn't know the program -- about the program at all or they have heard of it but knew very little.

We think we can help CARB staff in getting CNG users informed and ready when the requirements kick in. (SCG5_ST38-4)

Agency Response: Staff appreciates the commenter's support with data collection and outreach efforts for effective program implementation.

D-4. *Renewable Natural Gas*

No comments were received on this topic during the 2nd Board Hearing.

D-5. *Hydrogen*

No comments were received on this topic during the 2nd Board Hearing.

D-6. *Electricity*

D-6.1. *Support for the Proposed Electricity Provisions*

D-6.1a. *Support for the Proposed Electricity Provisions*

Comment: So I'd just say overall we appreciate the alignment of the LCFS with the goals for a greater electrification from the public health perspectives, so thank you all very much. (ALA1_ST7-5)

Agency Response: Staff appreciates the support for amendments that promote greater electrification of the transportation sector.

D-6.1b. *Support for the Proposed Rebate Amount Tiers Based on Rated Battery Capacity*

Comment: We also support staff's recommendation to set rebate amounts based on battery capacity. (CCA3_ST20-5a)

Agency Response: Please see Response D-6.25a, General Support for a Statewide Point-of-Purchase Rebate Program, in Chapter IV.

D-6.1c. *Support for the Proposed Addition of New Transportation Applications*

Comment: We strongly support the greater signal for electrification in the heavy-duty sector, creating and updating signals -- the credit signal for freight equipment. Transportation and refrigeration units, heavy-duty trucks and buses are important to pushing that sector towards electrification as quickly as possible. (ALA1_ST7-2)

Agency Response: Please see Response D-6.1f, Support for the Proposed Addition of New Transportation Applications, in Chapter IV.

D-6.1d. Multiple Comments: *Support LCFS for Promoting ZEV Adoption and Transportation Electrification in California*

Comment: Enhancements and amendments to the LCFS program in this rulemaking cycle are critical to reach the state's ambitious goals.

While we strongly -- ChargePoint strongly supports the increased opportunities for credit generation for electricity as a fuel. (CHARGEPOINT5_ST11-1)

Comment: Tesla's mission as a company is to accelerate the world's transition to sustainable energy. The LCFS regulation is directly supporting that transition. As well as the goals in California with regards to transportation electrification, climate, and air quality.

The refinements and the proposal really represents significant progress on all these fronts, and we support its full adoption. (TESLA3_ST29-1)

> **Agency Response:** Please see Response D-6.1j, Support LCFS for Promoting ZEV Adoption and Transportation Electrification in California, in Chapter IV.

D-6.1e. Multiple Comments: ***General Support for a Statewide Point-of-Purchase Rebate Program***

Comment: The utilities and the automakers unanimously support the adoption of the staff's proposal. And just so you know the framework we develop provides a statewide clean fuel reward for plug in electric vehicles of about a maximum of $2,000 at the time of purchase.

It's funded by a portion of the utilities, LCFS residential base credits. (UTILITYAUTO1_ST0-3)

Comment: Finally, I just wanted to quickly give you some of the highlights on the clean fuel, what our guiding principles were. Clearly, we want to accelerate the sales of cars that replace gasoline with electricity. That's the number one target. We wanted to provide a substantially larger reward than what the utilities were already providing. We wanted to make it simple for the dealers to implement and administer. We wanted to make it simple for the customers as well to understand.

We wanted to support the utilities local complimentary programs that they offer to their customers. So programs like EV outreach and awareness, utility grid planning adoption of time-of-day or time-of-use planning.

And we -- finally, we want to compliment the local, State, and federal programs such as CDRP, HOV stickers, the federal tax credit, and the equity programs that the utilities provide.

…

So with that, please, Mary -- sorry, Chair Nichols, strong support and thank you. (UTILITYAUTO1_ST0-4)

Comment: On the light-duty sector, we very much applaud your works, Ms. Berg, for pushing forward on the point-of-purchase program. This is been a long-time goal that we've supported, and we're really heartened to see this moving forward.

We also support and appreciate all the work that the automakers and the utilities put forward to make that happen. As that goes forward, we would like to see anywhere that we can make possible recommendations for greater incentive for lower and moderate income consumers to really help accelerate those choices and make them more real on the hood. (ALA1_ST7-3)

Comment: CCA supports the creation of an on-the-hood clean fuel reward for the purchase of a new electric vehicle. We also support the greater incentives for low-income and moderate-income consumers for the purchase of an EV. (CCA3_ST20-4)

Comment: On the clean fuels reward program for EV customers, I want to express my appreciation for staff and Board Member Berg's important critical efforts to convene stakeholders to reach alignment. It will make the program more consumer friendly by having the value returned at the point of purchase. (NRDC5_ST24-2)

Comment: With regards to the fuel rebate program, we look forward for its availability to all Californians who purchase EVs, and who are using these clean fuels.

And thank you so much to Steve for helping present that view for us. But on other topics we will continue to present our views to you directly. (TESLA3_ST29-2)

Comment: We continue to enthusiastically support the LCFS, its recent directions, and this -- point of proposal -- excuse me, the point-of-purchase proposal specifically.

We commend the -- excuse me. We commend Vice Chair Berg, also Eileen and Steve specifically, numerous Board Members, including Floyd.

…

Also the whole team. I think everybody has done such a great job, and the utilities and automakers that have put this together. We're very excited about it. No caveats or requests. (CALSTART4_ST32-1)

> **Agency Response:** Please see Response D-6.25a, General Support for a Statewide Point-of-Purchase Rebate Program, in Chapter IV.

D-6.2. ***Recommendations for Credit Generator for Multi-Family Residential EV Charging***

Comment: While we strongly support, we have two recommendations for further improvement and future consideration.

First, ChargePoint strongly recommends re-considering keeping out -- keeping opt-in EDUs as the eligible credit generator for electric vehicle charging at multi-family residences. The entity-owning FSE and multi-family residence should be able to generate credits, for a couple of reasons. Multi-family residences are typically very underserved when it comes to EV infrastructure. So if EV charging at multi-family

residence is its own category, credits could go directly to the multi-family residences, reducing payback period for their investment and creating funds to purchase more chargers and cover installation costs.

Additionally, ChargePoint believes that allowing multi-family residences to be able to collect credits will promote equity, breaking the cycle of predominantly lower income Californians from being locked out of clean technology due to energy poverty. (CHARGEPOINT5_ST11-2)

> **Agency Response:** Please see Response D-6.6 in Chapter VI.

D-6.3. ***Proposed Hierarchy for Incremental Credits for Residential EV Charging***

Comment: ChargePoint -- additionally, ChargePoint recommends revisiting the residential incremental credit hierarchy as we move forward to continue to improve it over time.

Thank you Board and staff again for the opportunity to comment and all of the hard work on this program. (CHARGEPOINT5_ST11-3)

> **Agency Response:** Staff is committed to working with stakeholders to make necessary updates to the program for promoting electricity as a low carbon transportation fuel.
>
> Please also see Response D-6.10, Proposed Hierarchy for Incremental Credits for Residential EV Charging, in Chapter V.

D-6.4. ***Implementation of Statewide Point-of-Purchase Rebate Program***

D-6.4a. Multiple Comments: ***Implementation Details of Statewide Point-of-Purchase Rebate Program***

Comment: So in terms of governance, following the adoption of the LCFS, the joint auto and utilities would like to continue to work with CARB to execute a governance agreement for the clean fuel reward program.

The governance structure would clearly identify the utility's responsibilities, the management structure for the program, and the accountability metrics to measure program success.

The joint auto and utility group also supports a third-party administrator to administer this program. And that administrator would be funded -- would be overseen by the funding utilities.

…

To ensure the financial stability of the clean fuel reward and avoid stops and starts or uncertainty. The clean fuel reward will establish a beginning balance, which is really

important to cover just the upfront costs the, start-up costs, including administration, and the first few year to three years of implementation.

We also want to make sure there is a strong cash reserve, so there's a -- so we do not end up in the red. We don't end up having to stop the program as has sometimes happened in some of the other reward or rebate programs. And then finally we want to make it very clear that the principal goal of this joint group is to make that reward as high as possible. We don't want a giant reserve. We want to spend this money the way this Board directed us to do, and we're all very supportive of that.

Utilities and the automakers jointly created a cash flow model, and that model is particularly sensitive -- I just wanted to make sure that you know this to the LCFS credit value, per ton valley of the CI of electricity, and the EV adoption curve.

With the Board's approval, CARB would like to continue to work with CARB and the utilities and automakers to improve that model.

…

We are -- in turn -- we are looking at finalizing the governance agreement by the end of this year, and with -- along as this gets approved today, we want the CPUC process to be completed by mid-2019, and we intend to work with them very collaboratively.

We would like to hire a statewide administrator, and get that person on Board by mid-2019, and then implement this program by the end of 2019. (UTILITYAUTO1_ST0-5)

Comment: CCA would like to see the point-of-sale program at car lots throughout the state no later than the fourth quarter of 2019. (CCA3_ST20-5b)

Comment: Very briefly, three small points to put in the hopper for you. One, around the EV point-of-purchase rebates, we are very supportive of that moving forward. Obviously, the devil is always in the details, and we hope that it -- this process allows for meaningful stakeholder input going forward, particularly beyond the stakeholders that have been involved thus far. So I'll just raise that. (UCS5_ST30-2)

> **Agency Response:** Please see Response D-6.13i, Implementation Details of Statewide Point-of-Purchase Rebate Program, in Chapter VI.

D-6.4b. *Stakeholder Engagement*

Comment: But I do want to just take this moment to say that outside of the POP proposal itself, we do all have our work continued to be cut out for us to make sure that we have sufficient stable incentives for EVs broadly. And we are particularly concerned about the automakers who have done the most to lead and which are hitting the federal caps and losing support on the federal side. And wondering if, maybe as we go forward, we can look for ways to either backstop or fix that through the LCFS.

So thank you and look forward to helping with this program's success. (CALSTART4_ST32-2)

> **Agency Response:** Please see Response D-6.13b, General Support for a Statewide Point of Purchase Rebate Program, in Chapter VI

D-6.4c. ***Role of Utilities in Promoting Electricity as a Transportation Fuel in California***

Comment: It's really important to note that the utilities have all begun to implement very important programs in their local utility districts or utility -- their -- sorry -- their service territories, and those programs are working.

As the utilities develop to these programs in their service territories, they worked together to come up with some shared goals. They definitely want whatever programs they implement locally to benefit both current or future customers. And they want to accelerate for the market for vehicles that use electricity as a fuel and remove any barriers.

In coming up with these programs, the utilities did research to look at what are the barriers, and what is the utility's role in effectively overcoming these barriers. They also worked with their public utilities commission, if they were investor-owned utilities. And municipal utilities not only worked with their governing boards, they also, in some cases, held town hall meetings to find out what their customers wanted in their service territories.

Some examples of these programs, just to give you an idea. There are equity programs that make driving electric vehicles available to everyone, whether they're in low-income communities or disadvantaged communities. They have secondary market incentives, so that means used vehicle incentives, if you will. They have -- almost all the utilities are investing in fueling infrastructure, particularly focused on low-income and disadvantaged communities. They have customer outreach and education programs, and they're looking at dealership outreach and assistance. (UTILITYAUTO1_ST0-6)

> **Agency Response:** Staff recognizes that utility programs can play a critical in supporting EV adoption to meet California's ZEV targets. Therefore, staff proposed to keep utilities as the default credit generator for base credits. Moreover, staff also proposed that any base credits (or resulting proceeds) that are not contributed to the statewide point-of-purchase rebate program could be used for other utility specific program to help support EV adoption. Please also see Responses D-6.1k, Support Electric Distribution Utilities (EDU) as Base Credit Generator for Residential EV Charging, and D-6.25e, Role of Public Utilities in Promoting Electricity as a Transportation Fuel in California, in Chapter IV.

E. Regulated Entities

No comments were received on this topic during the 2nd Board Hearing.

F. Average Carbon Intensity Requirements and Fuel Availability

F-1. Multiple Comments: *Support the 2030 CI Target*

Comment: We support the adoption of the strong 2030 target, because it creates a big umbrella for an innovation for public health protection, and a wide variety of cleaner fuels to contribute to meeting our clean air and climate change needs.

We see the LCFS as a key driver of cleaner fuels that continues to evolve for the better. The amendments just strengthen that signal that you're considering right now. (ALA1_ST7-1)

Comment: Second, on behalf of the Low Carbon Fuels Coalition, we stand in strong support of the program extension to 2030, and the carbon intensity reductions, again no caveats or requests here. And wonderful work done by all on this program. (LCFC2_ST19b-1)

Comment: CCA supports the 2030 target for reducing the carbon intensity of transportation fuels by 20 percent. (CCA3_ST20-2)

Comment: I'm here today to thank Board Members and staff for their hard work and due diligence in designing a comprehensive and thoughtful regulatory package to strengthen targets in the LCFS. (RNGC4_ST21-1)

Comment: First, we strongly support the increased goal of 20 percent by 2030, and I hope that we'll be back here before long actually increasing that goal even further. (BAC3_ST25-1)

Comment: You know and we're very excited about the new goal in 2030 with a 20 percent reduction. One of the things that we love about this rule is that it's fuel neutral, that it drives competition, it drives innovation. And that is happening. You're seeing the investments being made. (CE6_ST28-2)

Comment: And ARB can go even further than the 20 percent carbon intensity target based on other fuel availability assessments.

The LCFS has a strong track record of success, reducing carbon emissions, petroleum use, and public health costs. The LCFS is also a powerful driver of California's clean energy economy. These ambitious and achievable standards provide the market signal uncertainty for the investment that drives innovation. In fact, it is programs like the LCFS that makes California the nation's leading clean energy economy. (EE1_ST31-3)

> **Agency Response:** Staff thanks the commenters for their support of increasing the target of 20 percent CI reduction by 2030. Several comments suggested that the LCFS can achieve even higher CI reduction targets. For a discussion on the feasibility of higher targets, please see Response F-2.2. in Chapter IV.

F-2. *Fuel Availability*

Comment: We believe 20 percent is well within reach and could easily be exceeded through the continued expansion of alternative fuel options. (CCA3_ST20-3)

> **Agency Response:** Staff agrees with the comment that 20 percent CI reduction are achievable by 2030.

G. Credit Provisions

No comments were received on this topic during the 2nd Board Hearing.

H. Buffer Account

H-1. *Support for Proposed Buffer Account Provisions*

Comment: Additionally, the buffer account is an encouraging step to provide obligated market participants some form of insurance in the event an entity has inadvertently purchased invalid credits. (ANDEAVOR3_ST23-3)

> **Agency Response:** Please see Response H-1, Support for the Proposed Buffer Account Provisions, in Chapter IV.

I. Infrastructure Crediting

I-1. Multiple Comments: *Support for Proposed Infrastructure Crediting Provisions*

Comment: But we're in strong support of the proposal, especially as it relates to the ZEV capacity credits. It delivers on the Governor's Executive Order that was issued in January, and we're really excited to see it. I think as you know our ZEV future really depends on infrastructure, and the LCFS capacity credits are key in their innovative policy mainly because they're scalable.

And what this market real needs now at this point to meet our long-term goals is scale. And it also encourages renewable fuels, which we're very excited about. So thank you to the Board. Commend the Board and to the staff for everything you've done and strong support. (ZEVI1_ST2-1)

Comment: Our industry represents the 100 members in the fuel cell and hydrogen industry. And we are here to support the ZEV capacity credit… (CHBC3_ST33-1)

Comment: …I'll simply say that we strongly support it. (H2IND5_ST34-2)

Comment: In addition to our so support for the clean fuel rewards through the coalition presentation provided earlier, Global Automakers and the Alliance of Automobile Manufacturers want to offer support for the hydrogen refueling and DC fast charger capacity credits today as well.

There's very specific targets for both of these under the Governor's Executive Order. And as all -- we're all working to increase electrification, we need infrastructure development to keep pace with the growing number of vehicles coming to market.

Some of the infrastructure, however, remains expensive, and so in the interim it's important to use smart policies to help temper those costs, and continue to move infrastructure forward. (GA1_ST36-1)

> **Agency Response:** Staff appreciates the general support for the infrastructure crediting provisions.

I-2. *Not in Support for the Proposed Infrastructure Crediting Provisions*

I-2.1. Multiple Comments: *Generally Opposed to the Proposed Infrastructure Crediting Provisions*

Comment: Finally, I do want to echo many of the earlier comments, and I think subsequent comments about the infrastructure capacity credits. We're very concerned about the role of these credits. We support additional incentives to further the market as quickly as possible. But one of the strengths of this program is its emphasis on science-based life cycle carbon intensity.

And so we think that whatever additional incentives and credits should be offered should continue to be based on carbon -- life cycle carbon intensity of the fuels. And at a minimum if you are going to pick particular technologies, which I understand was in response to the Governor's executive order, those same incentives should at least be offered to other fuels and technologies that provide the same or lower carbon intensity. (BAC3_ST25-3)

Agency Response: Please see Response I-2.1 in Chapter VI.

I-2.2. Multiple Comments: ***Reduction in GHG Emissions Benefits and Excessive Revenue as a Result of Infrastructure Crediting Provisions***

Comment: There's one area we still have a real significant concern and it echoes a lot of what several other speakers before me, and a few who are coming after me, are going to say, and that is on the capacity credit provisions, particularly the hydrogen side of the capacity credit provisions.

We definitely recognize the desire to support these fuels getting into the market more quickly. We do think that there is such a thing as too much, though. And we think that particularly on the hydrogen side, that it hits that level of being too much.

We did quite a bit of modeling that we submitted with a comment over the last year, where we used the latest values from CEC and NREL to look at what likely performance of these are and show that it's likely to deliver far in excess of what it actually cost to build the stations, and so we have submitted some proposed resolution language that instructs staff to look at these the next opportunity at the next LCFS amendment to determine whether they're set at an efficient and appropriate level. We recognize there is language in the provisions before you.

But the language that's in the staff's package really looks to see whether or not this is going to do enough to achieve the goals, particularly the Governor's infrastructure targets. We think that that's not really a concern, that this is certainly going to achieve those goals. We think that it's likely that this is going to provide too much and end up not being a cost effective way to develop a strong and self-sustaining industry in the situation.

And so we're just asking to have a little extra attention paid to that over the next couple years, and we'll come back when there's more data from the program, determine whether or not there's more efficient way to achieve the same goals. (NEXTGEN5_ST27-3)

Agency Response: Please see Response I-2.5 in Chapter VI.

I-3. Multiple Comments: *Ongoing Review of Performance of Infrastructure Credit Provisions*

Comment: We have one outstanding area of great concern, however, and we ask the Board to issue an instruction to staff as they vote to re-adopt, in order to ensure that any potential harms are mitigated.

CARB should instruct staff to review the proposed capacity credit pathways before the next LCFS amendment rulemaking to ensure they provide an efficient and appropriate level of support.

We are deeply concerned that the proposed infrastructure capacity credits create an open-ended, inefficient and unnecessary commitment of revenue from the LCFS program, which will ultimately prove counterproductive to the State's climate and clean energy goals. While we recognize the value in supporting the deployment of ZEV infrastructure, the HRI proposal in particular will likely provide financial assistance significantly in excess of the actual costs to deploy the desire network of stations. **We urge the Board to instruct staff to return to this issue at their earliest convenience, to review the early performance of this program and conduct a thorough evaluation of the appropriateness of the levels of support offered by the infrastructure credit provision.[4]**

[4] Please refer to the suggested resolution language, attached to this submission.

By instructing staff to return to this issue during the next LCFS amendment process, CARB will ensure that a thorough evaluation of the incentives can be conducted, informed by the data submitted in the first wave of applications to the HRI program and supported by a public engagement process. Issuing a directed instruction now, as part of the amendment process, creates a clear and transparent signal to markets and researchers, which will allow for a robust and transparent review process.

…

THEREFORE BE IT RESOLVED that CARB instructs LCFS program staff to review the infrastructure capacity credit provisions to determine whether these provisions provide an efficient and appropriate level of incentive to achieve California's climate and clean air goals.

BE IT FURTHER RESOLVED that this review shall be completed in time to be given full consideration by the Board at the next rulemaking to amend the LCFS.

BE IT FURTHER RESOLVED that if this review finds that the level of incentive is not an appropriate and efficient mechanism to support deployment of ZEV infrastructure, staff shall propose amendments at the next LCFS amendment rulemaking to ensure incentives for ZEV infrastructure deployment are set at an efficient and appropriate level. (NEXTGEN6_SB5-4)

Comment: On the hydrogen and fast charging provisions, I certainly appreciate the goals and the need to build out the infrastructure, and would only ask that as this piece

moves forward that the Board really does take a hard look at any changes, or unintended consequences, or cost effectiveness challenges that might arise as it moves forward.

We do very much appreciate the need to expand the infrastructure we need for zero-emission technologies and hydrogen technologies, and would just say that over the course of this program, that course corrections have been -- played a very important role, and we expect nothing else from this Board. (ALA1_ST7-4)

Comment: Separately, at the next LCFS amendment opportunity, we'd like CARB to re-examine if the hydrogen infrastructure provisions are set at an efficient and appropriate level. (EDF2_ST16-4)

Comment: I will note that we did sign onto a letter asking you to reevaluate the capacity crediting provisions based on merit and efficacy at your earliest opportunity, and support the resolution that's been circulated by that Coalition on this issue. (RNGC4_ST21-3)

Comment: Finally, I know there have been some concerns expressed by numerous stakeholders, including NRDC around the infrastructure-based crediting approach. Staff's inclusion of limitations and guardrails around these provisions are a good start to ensuring that crediting doesn't get out of hand, and we support their proposed resolution for ARB staff to come back and make technical adjustments as needed. (NRDC5_ST24-3)

Comment: The one concern we do have, and it's the reason why we're, you know, shyly neutral, and -- but really want to be in the support category, because we love the rule, is largely due to the capacity credit provision. We think it takes the rule in another direction where we're worried about the validity of the credits. We, as you know, filed many amicus briefs in support of this program. We love this program.

So like Colin Murphy said, I would really like to support some more consideration thought in the next go around. We don't want to get in the way of the rule. We want to move forward. But I hope that there is some more consideration. We also understand there's an executive order, and there's marching to be done. But this is a really important rule for us. And so I just urge being careful. (CE6_ST28-3)

Comment: Second, around hydrogen fueling infrastructure credits, agree with many that they should be monitored to make sure the levels support is appropriate, and depending on the findings that a cap on the total credits per station may be warranted in the future. (UCS5_ST30-3)

Comment: Lastly, regarding the amendment related to capacity credits for fast charging hydrogen fueling infrastructure, if this amendment does move forward, we believe a thorough review of hydrogen station capacity credit generation is warranted to ensure that the environmental benefits of the program are not diluted by inflated credit generation that does not reflect actual low carbon fuel deployment. (CCA3_ST20-6)

Agency Response: Please see Response I-6 in Chapter VI.

J. Pathway Application and Carbon Intensity Determination

J-1. *Support for Modifications to the Pathway Application and Carbon Intensity Determination Provisions*

J-1.1. *Support for Updates to Sorghum Inputs in CA-GREET3.0*

Comment: I also want to call out Anil Prabhu who was extremely helpful with Sam and some of the other staff, specifically on some of the revisions to the GREET model. Really was able to update that model to have a more realistic assessment of sorghum across the country. (CONESTOGA3_ST15-4)

> **Agency Response:** Staff appreciates the support for collaboration with staff and updates to sorghum inputs in CA-GREET3.0.

J-2. *Simplified CI Calculator for Sugarcane-Derived Ethanol*

J-2.1. Multiple Comments: *Mechanization*

Comment: First, the calculator continues to discount the significant investments our members have made to reduce emissions through greater mechanization in harvesting processes. As our written comments on August 30th make clear, current assumptions do not match reality for most of our members. We encourage CARB to both raise the proposed default assumptions and allow our members to provide site-specific mechanization levels for their individual mills. Assuming that 20% of sugarcane crops in the State of Sao Paulo, and 35% in the rest of the country, are burned for harvesting is too far from Brazilian reality. Biofuel producers who have invested in modern, expensive technology should not be penalized by lower default assumptions. (UNICA6_SB6-1)

Comment: First, in our concerns are regarding to the calculator -- the CI calculator for sugar cane ethanol. First concern is that the lack of sell -- self-declared mechanization input, and the assumption that 20 percent of cane crops in Sao Paulo and 35 percent of cane crops in the entire Brazil are burned for harvesting. It's just too far from our reality. (UNICA5_ST26-2)

> **Agency Response:** Please see Response J-4.3 in Chapter VI.

J-2.2. Multiple Comments: *Maritime Transportation*

Comment: Secondly, UNICA is very concerned that CARB staff continue to apply so-called "back-haul" penalties for maritime transportation. Simply put, ocean tankers bringing ethanol from Brazil to California ***do not*** return empty to Brazil, and sugarcane ethanol ***should not*** be penalized for false assumptions unsupported by current market and trading practices. We understand CARB aims at having consistency and, as stated by Sam Wade during the last workshop, your goal is "to treat all back-haul fairly across all fuels". Fair treatment requires that specific realities are taken into account, so CARB

should publish any evidence that would justify the imposition of a back-haul penalty on sugarcane ethanol, or otherwise, remove it from the calculator. (UNICA6_SB6-2)

Comment: The second concern is with a back haul penalties for maritime transportation. Simply put, ships coming from Brazil to deliver ethanol to California will not go back empty to Brazil. We have not seen evidence to the contrary, and we wish this were removed from the calculator. (UNICA5_ST26-3)

Agency Response: Please see Response J-4.4 in Chapter VI.

J-2.3. ***Economic Impact***

J-2.3a. **Comment:** Finally, I want to underscore that these problems with low mechanization assumptions, unnecessary back-haul penalties and other technical concerns raised in our written comments have significant economic consequences. Considering current average carbon prices, proposed changes to the CI calculator result in an additional burden of nearly 25 cents per gallon for sugarcane ethanol. This unsupported quarter-per-gallon penalty means unnecessary costs for Californians, decreased investment in our industry and a potentially reduced supply of low-carbon fuels for the state. (UNICA6_SB6-3)

Agency Response: Please see Response J-4.6 in Chapter VI.

J-2.3b. **Comment:** UNICA understands and supports CARB's desire to enhance the low carbon fuel standard. Our comments are intended to ensure the proposed amendments have their desired effect and allow more low-carbon sugarcane ethanol to reach Californian ports and gas tanks. To accomplish this goal, CARB needs to revisit the calculator. (UNICA6_SB6-4)

Agency Response: Please see Response J-4.7 in Chapter VI.

K. Crude Oil and Innovative Crude Production Method Provisions

K-1. *Support for Proposed Amendments to the Innovative Crude Production Provisions*

Comment: And I wanted to thank staff and the Board for the work that you've done with us over the years in creating and -- the innovative crude program and making it possible for solar energy to -- participating and transforming the production and supply of liquid fuels.

This -- the LCFS is creating a driving force that is opening a fundamentally new market for solar energy. Solar energy projects will be here in California reducing combustion and NOx emissions in the communities that you were just speaking to in the last session, and creating permanent jobs here in the state.

We are grateful for the work that staff has done in this round of amendments that address a number of technical and commercial issues that will make it possible for projects to be project financed. As you know, in November, we announce the first of what we hope will be a series of projects. Belridge Solar we expect, with the adoption of these regulations, to move forward with a series of these projects. And we agree with staff's assessment that the petroleum sector could provide perhaps eight percent of the total credits going forward. So we are -- we're very optimistic and we support adoption of these amendments. (GLASSPOINT3_ST35-1)

> **Agency Response:** Staff appreciates the support for the proposed changes to the innovative crude provision.

K-2. *Innovative Crude Production Methods – Book-and-Claim Accounting for Electricity and RNG*

Comment: In the revised innovative crude provisions, CARB has proposed to not credit, book, and claim for renewable natural gas used as a process fuel. Similarly, book and claim is not allowed as accredited electricity source for solar that's not directly connected to the field. And I think, in short, that we're missing a great opportunity to get both RNG and electricity into the transportation system under the Low Carbon Fuel Standard.

It also is an alignment with several recently passed laws, namely SB 1383, which says to reduce methane emissions. We'd have the opportunity to export that great law around the country. In addition, recently passed AB 3187 and SB 1440, both which deal with renewable natural gas.

In summary, CRC views the requirement for physical direct supply of RNG and solar energy to crude oil production facilities as missed opportunities. (CRC2_ST6-1)

> **Agency Response:** Please see Response K-3.3 in Chapter V on Book-and-Claim Accounting for Electricity and RNG.

L. Refinery-Related Provisions

L-1. Multiple Comments: *Support for Proposed Refinery Investment Credit Program*

Comment: So, I would like to make three quick points tonight. The first one, I want to express appreciation and improvement of the refinery investment credit program, which we've worked on so hard. The program can now incent short -- short -- or near-term, rather, improvements that are often with environmental co-benefits. And then in the longer term, I think it's going to incent transformational technologies, which is what we're all looking for.

And finally for WSPA, the program reflects the type of fuel neutrality which we feel is essential to the LCFS regulations. (WSPA10_ST18-2)

Comment: First, thank you for the work that Sam and the staff have done to advance large portions of this regulation, specifically enhancing the refinery investment credit program.

Directionally, these changes will allow Andeavor to better evaluate and value process improvement projects in reducing the CI of the fuel that we produce. (ANDEAVOR3_ST23-2)

> **Agency Response:** Staff appreciates the support for amendments to the Refinery Investment Credit Program.

M. Carbon Capture and Sequestration

M-1. Multiple Comments: *Support for the Proposed Carbon Capture and Sequestration Provisions*

Comment: CCS is a critical technology that can facilitate deep decarbonization for California, and other jurisdiction. The recent passage of SB 100 and the Governor's carbon neutrality Executive Order place added importance on its deployment. This CCS Protocol under consideration today is the most comprehensive piece of CCS regulation ever assembled.

It is a product of diligent and thorough work by an extremely capable and professional team of staff over the past several years, and we are indebted to ARB staff for this landmark contribution to CCS regulation.

None of -- none of the pitfalls of past subsurface leakages that we have closely examined would ever remotely make it through this Protocol, which avoids -- or sets new standards for regulation of the subsurface. In short, we strongly urge the adoption of the Protocol today, and I will curtail my praise for this product in the interest of time.

We also support the provisions in resolution 18-34 that call for the continual improvement of this document. It is important for a document of this nature to remain current with technology, and to be improved through experience. (NRDC4_ST8-1)

Comment: And I'd like to point out that 45 years worth of geologic sequestration records suggest that atmospheric leakage of CO2 from properly sited geologic reservoirs is extremely unlikely. So given this, CCS -- or carbon capture and geologic CO2 storage can play a really important role in the LCFS. So I want to congratulate ARB for including this in their -- under the LCFS, and we fully support the adoption of the CCS protocol into the LCFS.

…

So in all, once again, thank you so much. Fully support the protocol. Would love for you to accept the resolution language. (CATF4_ST9-1)

Comment: Carbon capture and sequestration is also an issue EDF has been working on for every years in California and nationwide, and we're pleased to see a protocol included in this LCFS package. CCS is an important part of the energy -- energy sector's solution to climate change. And the work by ARB staff has been important to move this issue forward. At the same time, we also support the resolution before you related to a technical fix to the protocol's provision on monitoring. (EDF2_ST16-2)

Comment: Geologic trapping of CO_2 is a mature technology. Forty-five years worth of record suggests that atmospheric leakage of CO_2 from properly-sited geologic reservoirs is extremely unlikely. Given this, carbon capture and geologic CO_2 storage can play an important role under the LCFS.

I want to congratulate the team at ARB for their leadership in developing the Protocol, which allows CCS projects to contribute to meeting California's climate targets under the LCFS. CATF fully supports the incorporation of the CCS Protocol into the LCFS.

Once again, CATF fully supports the CCS Protocol and urges the Board to adopt the proposed resolution language. Thank you. (CATF5_SB4-1)

Comment: We also appreciate the opportunity to have commented and being part of the, you know, discussions and part -- and we appreciate that some of our recommendations have been included in the past. (CATF4_ST9-2)

Comment: We appreciate the opportunity to have recommended targeted changes to earlier drafts of the Protocol, and we appreciate that some of these recommendations have been included. (CATF5_SB4-2)

Comment: Additionally, I also want to add that the recently set goals of 100 percent clean electricity and carbon neutrality -- economy-wide carbon neutrality by 2045 and the maintaining of net negative emissions thereafter makes the CCS protocol all the more important than it was before.

So CCS may not only play a role in the LCFS or cap and trade, but it would most certainly play a role in the pursuit of negative missions through the use of direct air capture, and bioenergy CCS. (CATF4_ST9-4)

Comment: The recently enacted SB 100 establishes the important goal of 100% clean electricity by 2045. In addition, Executive Order B-55-18 appropriately goes even further and sets the target of state-wide carbon neutrality by 2045, followed by maintaining net negative emissions thereafter. As a result, this CCS Protocol becomes even more important for California's climate goals. Which means, that not only might CCS play an important role in the LCFS and through the cap and trade programs, but it will almost certainly play a crucial role in the pursuit of negative emissions through the use of Direct Air Capture or Bio Energy CCS. (CATF5_SB4-4)

Comment: The resultant Protocol is a rigorous regulatory document that requires applicants to submit 15 separate plans covering everything from site selection and subsurface modeling to monitoring and verification. It is a superior document likely to be replicated by other jurisdictions.

This is important because Occidental and White Energy have announced an engineering study to evaluate the feasibility of a joint carbon capture, utilization and storage project. The study is now examining the costs of building a carbon capture facility, drawing on Occidental's more than 40 years of experience in CO2 management. The project is designed to be eligible for carbon capture credits, including California's Low Carbon Fuel Standard credit program. Successful implementation will help demonstrate that the important incentives represented by CARB's efforts can result in near term investments that reduce carbon intensities in transportation fuels such as ethanol. (OCCIDENTAL7_SB2-4)

Comment: Occidental strongly supports … the quantification methodology that CARB has created to quantify the fuel pathways, as well as the resolutions before the Board for adoption of the carbon capture and sequestration protocol, as well as that resolution filed by George Peridas with NRDC.

We are heartened by CARB staff's engagement enthusiasm and energy in engaging with us during this process of developing this rule. The protocol is rigorous. It requires a submittal of 15 plans -- no less than 15 plans. I haven't fully counted, but I estimate approximately 800 provisions that a carbon capture and sequestration project will have to meet. This is critically important, because we need a protocol that we -- that can withstand scrutiny by the public and that will give you the assurances that any CO2 that we inject into the earth will remain there permanently. This is also important because we already inject two and a half billion standard cubic feet of CO2 per day from naturally occurring sources.

That's approximately one trillion standard cubic feet per year. We would like to replace as much of that as possible with anthropogenic CO2 for use in our floods. That is approximately 15 – 57 million tons of CO_2 on an annual basis.

Occidental and White Energy, the prior speaker, have already announced an engineering study to look at carbon capture technology and its application for ethanol production.

And we intend -- we fully intend to be first in line to see CARB's permanence certification upon passage of the LCFS amendments, as well as the approval of the CCS protocol. We look forward to working with CARB staff on implementation issues, and we thank you for your time. (OCCIDENTAL6_ST14-2)

Comment: Occidental Petroleum supports… the quantification methodology memorialized in the Carbon Capture and Sequestration Protocol (CCS Protocol). (OCCIDENTAL7_SB2-2)

Comment: In April of this year, Occidental appeared before this board to express its appreciation and support for CARB's leadership in these efforts. In the months since, we have met with CARB staff on several occasions to discuss many of the Protocol's specific provisions. CARB staff have been engaged, enthusiastic and extremely helpful throughout the rulemaking process. By way of example, in one meeting we arrived with four experts to explain in detail the advanced Supervisory Control and Data Acquisition systems we have that continuously collects and monitors data from sensors at each of our wells. We also described our use of fully peer reviewed main-line simulators to model complex reservoir geologies and performance. Throughout the meeting CARB staff displayed a deep understanding of our technology, its deployment and the challenges of CO2-EOR operations. (OCCIDENTAL7_SB2-3)

Comment: In closing, Occidental urges this Board to adopt the CCS Protocol… and we look forward to working with CARB staff to obtain permanence certification for our projects. (OCCIDENTAL7_SB2-8)

Comment: Two things, that we'd like to support … the CCS adoption, as well as some of the revisions that NRDC mentioned. (CONESTOGA3_ST15-3)

> **Agency Response:** Staff appreciates the commenters' support for the CCS provisions and Resolution 18-34 in which the Board directs the Executive Officer to monitor the development of science related to the implementation of the CCS Protocol and to propose technical updates to the Protocol as needed. Staff also appreciates the commenters' support for the Board to adopt the CCS Protocol for inclusion in the LCFS.

M-2. Multiple Comments: ***Technical Updates to the Protocol***

Comment: Of course, just like George just mentioned, one thing that we have communicated in the past is the -- is that the risk-based approach to monitoring and verification, it will provide the greatest security for the stored CO2, so we would -- we would definitely want to work together to further improve the protocol to adopt a risk-based monitoring and verification approach.

To this end, CATF joins the recommendation that was just made by George and request that the Board adopt the resolution that is presented before you in the printout. (CATF4_ST9-3)

Comment: As a licensed geologist in the state of California myself, I encourage CARB to incorporate flexibility in the provisions to allow for alternatives to the post-injection site closure monitoring. Geology for the sites and infrastructure and other factors demand site-specific monitoring plans with room for alternatives to both monitoring methods and durations.

So CRC is looking forward to working with CARB and other stakeholders to pursue safe, economically viable geologic sequestration projects to help achieve California's very ambitious climate goals. (CRC3_ST12-1)

Comment: And then lastly around the new provisions relating to carbon capture and sequestration, we agree that those as well are a good addition to the program. However, they, too, will require ongoing study, engagement with stakeholders, and appropriate amendments in the near future to address the methods, frequency, and duration for post-injection monitoring of CCS projects. (UCS5_ST30-4)

> **Agency Response:** Staff appreciates the commenters' support for the specific provisions in Resolution 18-34 which directs the Executive Officer to monitor the development of science related to the implementation of the CCS Protocol and to propose technical updates to the Protocol as needed. Staff will continue to work with stakeholders examine future technical updates on the Protocol.

M-3. Multiple Comments: *100-Year Post-Injection Site Care*

Comment: The undersigned hereby submit the following language for the Board's consideration in relation to revising provisions for post-injection monitoring under the CCS Protocol:

> *WHEREAS the CCS Protocol contains extensive requirements for minimizing risk and assuring permanent subsurface storage of carbon dioxide.*
>
> *WHEREAS by the time CCS projects regulated under the Protocol reach the post-injection phase, experience with, and data on, such projects will have increased significantly, and monitoring and scientific methods to estimate any residual risk of leakage, will very likely have evolved considerably and beyond what can be envisioned today, necessitating a risk-based approach to post-injection monitoring.*
>
> *NOW, THEREFORE, BE IT RESOLVED that the Board directs the Executive Officer to work with stakeholders, including scientists and researchers, project developers and environmental groups, to evaluate the optimal risk-based requirements for the methods, frequency and duration for post-injection monitoring of CCS projects after carbon dioxide plume stabilization has been established, how these requirements can accommodate both today's and future needs and technologies, and to propose scientifically supported and environmentally protective amendments to the relevant provisions of the CCS Protocol by October of 2019, including authorizing the termination of monitoring in the event that it can be demonstrated with a high degree of confidence that 100-year permanence will be achieved by a particular CCS project.* (NRDC6_SB1-1)

Comment: However, I must raise one issue and I'm not doing so lightly, especially given the lateness of the hour and the workload upon you today. We continue to have concerns about the post-injection monitoring provisions in the protocol, which appear to us to be dictated more by desire for consistency with the forestry protocol, a largely unrelated activity, than by current science.

The protocol mandates post-injection monitoring to continue over 100 years, but severely limits the monitoring methods that should be used, presumably in order to contain costs. As a result the environmental protection afforded by the proposed monitoring take sa *[sic]* hit.

We have also heard repeatedly from numerous other stakeholders that these provisions may also coincidentally be problematic for project development.

We have submitted a resolution language, which is in your materials in front of you, that would take care of this -- of this problem, and could call for a risk-based reevaluation of these monitoring provisions. We think that it's important for this agency to get it 100 percent right. So we urge passage of the protocol subject to hopefully these revisions, and we ask the Board to provide specific guidance today to that effect. (NRDC4_ST8-2)

Comment: …much like some of the other speakers here, I do have some concerns regarding the non-risk based approach for the 100-year permanence. We ask that you look at the resolution that has been put forth for you today, and take more of a performance based approach as these projects are long lived, and these projects have a long lead time.

You can take the information that as we engineer and design these new projects, and employ a protocol that will barely reward innovative changes to how this technology is deployed. (WE5_ST13-2)

Comment: One thing that we have communicated to ARB previously, and would want to continue to engage with ARB on, is that a risk-based approach to monitoring and verification will provide the greatest security for stored CO_2. Risk-based approach would mean a) identifying and requiring targeted monitoring and verification where the leakage risk would be most probable and b) utilizing monitoring and modeling to determine when injected CO_2 has stabilized and leakage risk is negligible. We look forward to working together further improve the Protocol, resulting in greater assurance of CO_2 storage security. To this end, CATF joins the recommendation presented just now by NRDC and requests the Board to direct ARB to evaluate a risk-based post-injection monitoring approach. (CATF5_SB4-3)

Comment: Point two is in regard to CCS, which you've heard a little bit about already tonight. We're supportive of CCS. We think there are a couple aspects that still need to be worked on. And I think you heard a little bit about that tonight, the hundred year post-project site care requirement. And also we want to make sure that the CCS program is written in such a manner that CCS regulations and other jurisdictions will actually be accepted here.

And to that end, we hope that as we go into next year, we'll open up -- continued discussions and work on the CCS protocol. (WSPA10_ST18-3)

Comment: Regarding the 100-year post closure period, we understand that there is a resolution before the board on this issue and support its adoption. We expect that technological improvements during long CCS project life cycles will enable some projects to demonstrate permanent geological storage sooner than the 100-year timeframe. Accordingly, Occidental recommends additions to the Protocol that permit a CCS Project to meet demanding performance-based criteria with a corresponding reduction in the post closure monitoring period. (OCCIDENTAL7_SB2-6)

> **Agency Response:** See Response M-6 in Chapter IV regarding the 100-year post-injection monitoring requirement and Response M-4.2 in Chapter V regarding the requirement in Board Resolution 18-34 to monitor the development of science related to the implementation of the CCS Protocol under the LCFS, and to propose technical updates to the CCS Protocol, as needed.

M-4. ***Access to Nearby Formations***

Comment: Regarding site-care, the Protocol proscribes certain activities commonly conducted in the vicinity of oil and gas production. These activities are conducted by others that own rights to access other formations near, but not within, a CO2-EOR project. Other formations can be safely accessed without threat to the CO2-EOR operations because drilling activities must always comport with state drilling rules implementing the Safe Drinking Water Act. These rules protect underground sources of drinking water from cross contamination and have a side benefit of also preventing the loss of CO2 from a CCS Project. Occidental welcomes the opportunity to work with CARB staff to incorporate additional requirements into the Protocol that would safeguard CCS Projects while recognizing that others may have rights to access other formations in the vicinity. (OCCIDENTAL7_SB2-5)

> **Agency Response:** Please see Responses M-23 in Chapter IV and M-13 in Chapter V regarding binding agreements that prohibit drilling or extraction that penetrate the confining layer above the sequestration zone of the storage complex and Response M-4.2 in Chapter V regarding the requirement in Board Resolution 18-34 to monitor the development of science related to the implementation of the CCS Protocol under the LCFS, and to propose technical updates to the CCS Protocol, as needed.

N. Reporting and Recordkeeping

No comments were received on this topic during the 2nd Board Hearing.

O. Third-Party Verification

No comments were received on this topic during the 2nd Board Hearing.

P. Alternative Diesel Fuel Regulation

P-1. *Support for Amendments to the Alternative Diesel Fuel Regulation*

Comment: We're very supportive of the package. Like I said, in particular I do want to call out the alternative diesel fuel provisions. I'm sure you're going to hear from other folks about different pieces. This is innovative I don't think everyone will be happy with every ticky-tack thing. But when you look at the pieces as a whole, staff should be commended. And I hope that quickly, whether it's tonight or tomorrow , it's adopted because it's the right thing to do. (REG5_ST1-2)

> **Agency Response:** Staff appreciates the support on the Alternative Diesel Fuel Provisions.

P-2. Multiple Comments: *General Comments on Bifurcation*

Comment: We have reviewed CARB's "Responses to Comments", dated September 17, 2018 and focused on the subject responses. California Fueling maintains its position regarding the practical concerns associated with the proposed ADF bifurcation concept. **The clarifications noted in CARB's subject comments differ significantly from our views and are worthy of further consideration before ruling on bifurcation.** (CAF5_SB3-1)

Comment: California Fueling has significant market experience promoting the use of B20 through our CARB approved NOx Mitigants. We have made our concerns known to CARB. We would appreciate it if CARB could investigate our positions, determine if they are correct and, in the meantime, not rule on bifurcation until a full investigation can be completed. (CAF5_SB3-4)

Comment: I've submitted two Documents raising concerns about bifurcation. I've placed in the record today another document objecting to bifurcation. In summary, CARB's view of the biodiesel marketplace is in error as evidenced by the response to comments FF02.

Today's letter seeks to set the record straight. In the best use of time, I respectfully request that each of you read our letter before finalizing your decision today.

My company has spent the last three years developing the B-20 market. I believe we have an accurate view of the marketplace. And from our vantage point, bifurcation doesn't make practical sense, and it doesn't make technical sense.

Most importantly, the market can simply not make room for another fuel. There's also the downside risk that biodiesel will not make its way in the off-road market, in which case emissions would increase in the areas of high off-road vehicle population areas.

The ADF's NOx mitigant requirements are in its infancy. We believe there are far more pressing needs within the ADF, functional improvements that need to be made to this regulation, as oppose to further complication. And bifurcation is a complication.

My company has been very forthright with CARB on many ADF improvements which need to be rectified in the short term. To that end, we've provided a short list of proposed regulatory changes that we believe will provide CARB with the tools to better achieve the ADF's mission.

As an example, we have identified that the existing ADF does not give CARB clear authority to address an issued Executive Order that may have improvidently been granted.

…

We've raised concerns about an EO that was issued where the representation was made in the EO that testing was done according to approved written protocols, but where we have since been told by both the testing facility and CARB staff that an oral modification to the testing protocols was approved by CARB staff.

When presented with these concerns, CARB has taken months to investigate, and, despite repeated assurances, still has not reached a resolution. It appears to us that CARB has been unable to determine whether it has the authority to require further supporting information or if it has the authority to suspend or withdraw an EO.

Moreover, CARB has apparently not analyzed what would happen to tax credits generated based on an EO that is suspended or withdrawn.

Regardless of the instant issue we have raised to CARB, it is clear to us that CARB should be provided with clear unambiguous regulatory authority as to how to proceed when faced with questions to an already issued Executive Order.

CARB should be provided with the tools to promptly address these sorts of issues, in an equitable fashion, equitable to the applicant, competitors, and consumers, who are acquiring the product in the associated tax credits, while at the same time making sure product is not causing harm to the environment. (CAF4_ST17-1)

> **Agency Response:** Staff appreciates the commenter's review of CARB's "Responses to Comments" dated September 17, 2018. Please see Responses P-3 through P-5 in this chapter addressing commenter's concerns related to staff's responses to comment CAF2_FF2-0 in the Responses to Comments on the Draft Environmental Analysis. Staff disagrees with California Fueling that there are practical concerns associated with the proposed bifurcation concept.
>
> Staff has reviewed the comment letters and Board Hearing testimony provided by California Fueling. Based on this review, staff retained the bifurcation provision in the amendments to the ADF regulation and the Board approved these amendments. Please see responses to comments CAF1_9-2 through CAF1_9-9, CAF2_FF2-0, CAF3_SF14-1, and GROWTHENERGY2_FF56-25 in the Responses to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel

Regulations, Responses P-2 through P-7 in Chapter V, and Responses P-3 through P-5 in this chapter.

The commenter also raised concerns about a previously-issued Executive Order unrelated to the current rulemaking. This portion of the comment is outside of the scope of this rulemaking.

P-3. Multiple Comments: *Impact of Bifurcation on B20 Market*

Comment: Bifurcation means another fuel in an already congested marketplace. The B20 market is in development; there's much work to be done to increase its market penetration. Presently, the majority of B20 is used on-road. If bifurcation is adopted now, less effort will be placed on developing the off-road B20 market. The inevitability of bifurcation is that off-road B20 will require a separate fuel in the marketplace. CARB has ruled on the side of conservatism on most LCFS and ADF related issues. The more conservative decision, based on the facts available at present, would be to walk back bifurcation until the B20 market further develops. What's the harm in holding off on bifurcation when doing so poses no risk? (CAF5_SB3-9)

Comment: 4. "Therefore, access to B20 would not be likely to be reduced, and a decrease in off-road B20 volumes in any portion of the diesel market, and any associated increases in criteria pollutants, would not be reasonably foreseeable."

a. Clarification: There is not an infinite number of biodiesel tanks available in California. Biodiesel is being stored at facilities across the state. If a bifurcation concept is adopted biodiesel providers will face the following choices:

   i. Lease more biodiesel tankage and invest in equipment to add NOX Mitigants, or

   ii. Focus on the bigger on-road B20 market, which is twice as big as the off-road market, not lease any more tankage or railcars and not purchase NOX Mitigant.

In our estimates, further capital will not be invested, and the focus will be on-road diesel. Supporting this conclusion is the fact that only **one** terminal has invested in the equipment to add NOX Mitigant as tank trucks are loaded with B20. (CAF5_SB3-8)

Agency Response: Staff disagrees with the commenter's assertion that less effort will be placed on developing the off-road B20 market if bifurcation is adopted now. With or without adoption of the bifurcation provision, B20 used in both sectors is required to be NOx-mitigated until the on-road sunset criteria are achieved (i.e., when the vehicle miles travelled (VMT) by on-road new technology diesel engine (NTDE) heavy-duty vehicles in California reaches 90 percent of total VMT by the California on-road heavy-duty diesel vehicle fleet). Staff estimates that the on-road sunset criteria will not be achieved until at least 2023, by which time staff projects the use of biodiesel to triple.

Staff also does not agree with the commenter's inference that there would be no harm in holding off on bifurcation for now. Requiring NOx mitigation for biodiesel blends in the on-road sector beyond when the sunset criteria are attained provides limited additional environmental benefits while increasing costs unnecessarily.

Staff disagrees with the commenter's analysis and conclusions related to availability of NOx-mitigated B20 in the off-road sector following adoption of a bifurcation concept. Please see Response P-5 in this chapter regarding an additional option that may cost less than adding additional storage and Response P-4 in this chapter regarding infrastructure.

In addition, staff disagrees with the commenter that biodiesel producers and suppliers may ignore the off-road B20 market following the sunset of in-use requirements for biodiesel in the on-road sector. Given the anticipated increase in demand for higher biodiesel blends and the relatively substantial off-road diesel market (i.e., approximately 25 percent to 30 percent of all mobile source diesel demand), staff anticipates that biodiesel producers and suppliers will continue to service the off-road biodiesel market beyond when in-use requirements for biodiesel sunset for the on-road sector.

P-4. Multiple Comments: *Bifurcation Infrastructure*

Comment: The infrastructure to blend biodiesel into diesel fuel is limited and cumbersome (see Attachment I for a pictorial view). There has been little to no capital investment made at fuel terminals to blend NOx Mitigant required levels of biodiesel which are splash blended. As a result, there's an inherent bottleneck to supplying biodiesel blends. CARB's forecasts show growth of biodiesel over time yet don't address the constrained assets to deliver those biodiesel volumes to the market. (CAF5_SB3-2)

Comment: 2. "no additional tankage or rail cars are reasonably likely to be needed to support staff's bifurcation proposal"

a. Clarification: in an ideal world CARB is correct, the addition of NOX mitigant would occur like red dye, added just before a tank truck is loaded at a terminal. To our knowledge, there is **one** fuel terminal in California that has the ability to do so. For the most part, NOX Mitigant is **not** added at a terminal but at a separate location where biodiesel is stored. B20 blending occurs "under the rack", downstream of the terminal. The process to tank truck blend biodiesel with diesel "under the rack" in known as "splash blending", mixing one component, diesel fuel, with another, biodiesel.

   NOX Mitigant is presently added into bulk biodiesel storage tanks which are not located at fuel terminals. With bifurcation, there's an added element of complexity. Two types of biodiesel would be required - one with NOX Mitigant, for off-road diesel, and one without, for on-road diesel. Segregation of on and off-

road biodiesel would have to occur. As a result, twice as many biodiesel storage tanks, railcars, etc would be required to provide two types of biodiesel. The only workaround is if NOX Mitigant, like red dye, would be added as biodiesel is loaded into a tank truck. To our knowledge, the workaround option has not been adopted in the marketplace because of the costs associated with the equipment to do so. (CAF5_SB3-6)

Comment: 3. "For the same reason, no additional costs related to additional storage capacity would likely be incurred to store additized B20 for off-road applications following the sunset of in-use requirements for on-road vehicles."

a. Clarification: Based on 2.a. above, bifurcation would require twice as many biodiesel tanks. Twice as many tanks means double the costs. Additionally, B20 is **not** stored in bulk storage (aside from when it's delivered to the end user), it's splash blended as noted above. (CAF5_SB3-7)

   Agency Response: The current infrastructure is sufficient to serve the existing biodiesel market. Staff projects increases in biodiesel consumption over time and expects that producers and suppliers will increase assets used to blend, mitigate, and deliver additional biodiesel volumes. Staff does not agree that there will be an inherent bottleneck to supplying biodiesel blends.

   Staff also disagrees that twice as many biodiesel storage tanks, railcars, etc would be required to provide two types of biodiesel (i.e., unmitigated biodiesel for the on-road sector and NOx-mitigated biodiesel for the off-road sector) following the sunset of in-use requirements for biodiesel in the on-road sector. Please see Response P-5 in this chapter regarding an additional option that may cost less than adding additional storage.

P-5. ***Blending Practice Under Bifurcation***

Comment: 1. “diesel fuel for on-road and off-road applications is already segregated”

a. Clarification: on-road and off-road diesel **are not** segregated fuels; the diesel portion of on and off-road fuel is identical, What makes off-road diesel different from on-road is that dye is added to diesel at “terminals” as fuel is loaded into a tank truck. Red dye is not added to diesel fuel in bulk tankage.

   Terminals handle biodiesel, but in most cases do so to blend B5 only. To our knowledge, there is **one** fuel terminal that blends B20 in tankage. If bifurcation was adopted, this terminal would be faced with blending off or on-road diesel, but not both unless an additional tank was placed in service. (CAF5_SB3-5)

   Agency Response: Staff understands that the diesel portion of on-road and off-road diesel is the same, and clarifies our response to comment CAF2_FF2-0 in the Responses to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel

Regulations to indicate that on-road and off-road diesel fuels are segregated following the addition of red dye to diesel fuel for the off-road market.

Staff disagrees with the commenter that, following the sunset of in-use requirements for biodiesel in the on-road market, fuel terminals that blend B20 in tankage would be faced with a decision to blend off- or on-road diesel, but not both, unless an additional tank was placed in service. An additional option is for fuel terminals to blend unmitigated B20 in tankage and NOx mitigate B20, as needed, when transferring from bulk biodiesel storage to tanker trucks, similar to how red dye is added to conventional diesel when being transferred from tankage to tanker trucks. This would allow terminals to produce biodiesel blends for both the on-road and off-road markets. Staff anticipates that the cost associated with this approach would likely be less than adding additional storage tanks for B20 at fuel terminals.

Q. Voluntary NOx Remediation Measure Funding and Draft Supplemental Disclosure Discussion of Oxides of Nitrogen Potentially Caused by the Low Carbon Fuel Standard Regulation

No comments were received on this topic during the 2nd Board Hearing.

R. Economic Analysis

No comments were received on this topic during the 2nd Board Hearing.

S. Environmental Analysis

S-1. Multiple Comments: *Comments on the Draft Environmental Analysis*

Comments: CAF5_SB3-3, GROWTHENERGY4_SB8- 1, GROWTHENERGY4_SB8-2, GROWTHENERGY4_SB8-3, GROWTHENERGY4_SB8-4, GROWTHENERGY4_SB8-5

> **Agency Response:** The responses to these comments are in "Supplemental Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations."

T. Fuel Neutrality

Please see Response I-3, Ongoing Review of Performance of Infrastructure Credit Provisions, in this chapter.

U. Rulemaking Procedure

U-1. Multiple Comments: Support for the LCFS Rulemaking Procedure

Comment: The Final Regulation Order which you will be voting on represents over a year's worth of effort from Staff and a broad group of stakeholders. We would like to commend Staff for their commitment to open discussions during this time and thank them for the tremendous effort they've put in.

We feel that the Final Regulatory Order, as presented, provides a strong foundation for future success and addresses most of the substantive issues we have raised over this rulemaking period. (NEXTGEN6_SB5-3)

Comment: Definitely want to extend my appreciation both to you all for the endurance you're displaying, also to the endurance of Sam and Jim and the rest of the LCFS team for the many conversations they've had including the quite a few that they had with me over the last year or so. (NEXTGEN5_ST27-1)

Comment: First, I'd really like to thank Vice Chair Berg for her leadership in this. And I'd also like to thank the ARB staff for all of their hard work. It was just five months ago that the Board asked the stakeholders to come together and develop a framework that would provide a larger clean fuel reward for replacing gasoline with electricity, and to provide that reward at -- up front at the point of purchase. I can tell you that this has not been easy.

…

However, with Vice Chair Berg's Leadership, representatives from every utility in California, every car company in California, and the California New Car Dealers Association have developed and agreed upon the framework. (UTILITYAUTO1_ST0-1)

Comment: This is an excellent process and an excellent program, and one that works. The staff -- and it would be great if we could name them, but there's frankly too many - have been terrific this year in engaging all the stakeholders. Mr. Corey runs an excellent shop and all of his folks are to be commended. We've had numerous meetings as both our own company, with our trade associations, and I will never refer to a regulatory process as enjoyable --

…

-- but this was a very easy process. (REG5_ST1-1)

Comment: We truly appreciate the professionalism, transparency, and hard work of staff in working with all stakeholders in preparing these proposed amendments for your consideration. (PERFA1_ST4-1)

Comment: We are extremely appreciative of the relationship we have with staff. Richard Corey runs the best shop in the country. He's to be commended for that. (NBB1_ST5-2)

Comment: I would like to thank the ARB senior leadership and staff for their hard work on this critical program.

…

I'd like to than the senior ARB leadership and staff for engaging with both the renewable and petroleum industries, as we work together on the LCFS and toward a cleaner California. (CRF3_ST10-1)

Comment: Richard has definitely got too much love tonight, so I wanted to call a shout-out to Sam Wade and his staff, who have spent a considerable --

…

-- amount of time, as well as many other folks. So thank you. (CONESTOGA3_ST15-1)

Comment: And I also wanted to express appreciation for staff for the process.

We've had so many opportunities for public outreach. It has been tremendous. In fact, my family has said to me I spend more time with Sam and his staff than I do with them. (WSPA10_ST18-1)

Comment: Board members, and especially Sam and his team have spent countless hours with me, and with our members working through numerous issues, most of which were resolved to our satisfaction, and we greatly appreciate that. (RNGC4_ST21-2)

Comment: First, thank you to ARB staff and management who have worked so hard over the past three years on this effort in an open transparent manner with all stakeholders. (NRDC5_ST24-1a)

Comment: Second I want to echo the thanks for staff, and especially, as I said a few months ago, at the hearing on LCFS. Staff responded very, very quickly about a mistake in definition of biomethane, and did agree to revise that definition and they have done so. And so I want to thank staff for being so responsive. (BAC3_ST25-2)

Comment: I'd like to start by thanking you, Board, and staff for all the great work you have done over the years on the Low Carbon Fuel Standard. It is certainly a policy that is driving leadership across the globe. (EE1_ST31-1)

Comment: First I want to commend Sam Wade and his team. It's been a long process. And throughout the process, they've been very open and responsive which we appreciate. (SCG5_ST38-1)

Agency Response: Staff appreciates the commenters' support for the rulemaking process and staff's efforts.

V. Analysis of Alternatives

No comments were received on this topic during the 2nd Board Hearing.

W. Miscellaneous

W-1. *Higher Ethanol Blends*

Comment: For future consideration, I'd like to provide our perspective on an important and valuable opportunity.

Facilitating the use of higher blends of low carbon high octane ethanol, and other biofuels could accelerate reductions in GHG emissions from California's transportation sector.

The ethanol industry is responding to the market signals of the LCFS by significantly reducing the carbon intensity of our fuel. Allowing for higher blends of lower carbon ethanol would, in turn, help significantly with further carbon reductions and are compatible with existing infrastructure and automobiles.

We're proud to be a primary contributor to the LCFS's success, and look forward to further driving down our carbon intensities in response to the program's goals and market-based incentives. (PERFA1_ST4-3)

> **Agency Response:** Please see the response to comment GROWTHENERGY1_B4-51 in the Response to Comments on the Draft Environmental Analysis for the Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations.

W-2. *Not Within Scope of Rulemaking*

W-2.1. *Market Stability*

Comment: We consult with an increasingly diverse set of low carbon fuel technology suppliers, and want to share just one thought with the Board, and that is we're observing a shift in the way investors are thinking about the market that you should be sensitive to.

Increasingly, the LCFS is becoming the central pillar in the investment thesis as compared to the renewable fuels standard. That's largely because of the stability of this program contrasted with increasing uncertainty being injected in the federal fuels programs. So keep up the good work. You're doing great, but keep a real close eye going forward on market stability questions. (AJW1_ST39-1)

> **Agency Response:** Staff appreciates the commenter's insights and recommendation to keep a close eye on market stability going forward.

W-2.2. *Cost Containment Mechanism*

Comment: And then the final item that I had, if you don't mind, some -- unfortunately, at the end, it's the most important one. And my third point is I think we're at a critical pivotal point of the LCFS program, in terms of feasibility. And so what I would like the

Board to do is encourage staff to engage in conversation with regard to cost containment.

Clearly, cost containment is the next step towards completing the LCFS process to make it work for everybody. I think you've heard it before and I think staff is well aware of it. So we would encourage you to push forward and have us have that critical discussion on cost containment. (WSPA10_ST18-4)

> **Agency Response:** Please see Response W-4 in Chapter IV and specifically to the response for WSPA4_T48-8 in that section.

W-3. Multiple Comments: ***Support for Other Commenters***

Comment: Additionally, Andeavor supports and incorporates the comments made by WSPA. (ANDEAVOR3_ST23-1)

Comment: I also want to support written comments from Air Liquide, Hyundai, Mercedes-Benz, Nel, Linde, and United Hydrogen. (H2IND5_ST34-1)

> **Agency Response:** Staff acknowledges these stakeholder comments in support of comments provided by other organizations. All comments submitted by the referenced organizations have been responded to elsewhere in the FSOR.

VIII. PEER REVIEW

Health and Safety Code section 57004 sets forth requirements for peer review of identified portions of rulemakings proposed by entities within the California Environmental Protection Agency, including CARB. Specifically, the scientific basis or scientific portion of a proposed rule may be subject to this peer review process. CARB determined that the rulemaking does not contain new scientific basis or a new scientific portions subject to peer review requirements set forth in section 57004, and thus no new peer review needed to be performed.