August 27, 2024

RE: International Council on Clean Transportation comments on the Proposed 15-day changes to Proposed Regulation Order

These comments are submitted by the International Council on Clean Transportation (ICCT). The ICCT is an independent nonprofit organization founded to provide unbiased research and technical analysis to environmental regulators. Our mission is to improve the environmental performance and energy efficiency of road, marine, and air transportation, in order to benefit public health and mitigate climate change. We promote best practices and comprehensive solutions to increase vehicle efficiency, increase the sustainability of alternative fuels, reduce pollution from the in-use fleet, and curtail emissions of local air pollutants and greenhouse gases (GHG) from international goods movement.

The ICCT welcomes the opportunity to provide comments on the Air Resources Board's proposed 15-day changes to the Low Carbon Fuel Standard amendments. We commend the agency for its technical analysis and interest in continuing to improve the effectiveness of one of its flagship climate programs. The comments below offer a number of technical observations and recommendations for ARB to consider in aligning the program with the goals of the 2022 Scoping Plan, restoring stable credit prices, and maintaining the environmental integrity of the program.

We would be glad to clarify or elaborate on any points made in the below comments. If there are any questions, ARB staff can feel free to contact Nik Pavlenko (n.pavlenko@theicct.org) and Dr. Stephanie Searle (stephanie@theicct.org).

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Summary of comments

These comments respond to the 15-day Low Carbon Fuel Standard (LCFS) package released on August 12th, 2024.[1] This package includes detailed changes to proposed regulatory amendments that were first published in December 2023. Recent amendments were made to better align the LCFS program with California's 2022 Scoping Plan goals and stabilize credit prices following consistent overcompliance with annual carbon intensity (CI) benchmark targets. Consistent over-compliance with the annual CI reduction target since 2020 has led to an excess of banked credits that must be drawn down before credit prices begin to rise.[2] In recent years, California's transportation sector has also undergone major changes to its transportation fuel mix, including rapid growth in renewable diesel, biomethane, and electricity crediting. Many of these developments were a direct result of LCFS policy although other external factors such as zero-emission vehicle (ZEV) mandates and federal fuel subsidies have accelerated growth in alternative fuel markets.

In the detailed technical comments below, we make several key recommendations:

- The cap on crediting for soy and canola biomass-based diesel beyond 20% of a company's volumes should be extended to all vegetable oils. For vegetable oils blended in excess of the cap, those fuels should be assigned the fossil diesel baseline CI rather than the benchmark CI.
- Vegetable oil-derived SAF has the same sustainability concerns as vegetable oil-derived biomass-based diesel, therefore it should not be excluded from crediting limitations.
- Update ILUC assessments for crop-derived biofuels to include more recent data and additional models.
- Implement third-party sustainability requirements for waste and residue biomass
- Restore the originally proposed obligation on intrastate jet fuel.
- Restore the originally proposed Clean Fuel Reward program for MDHDV rebates funded by base credit generation in lieu of the August proposal to issue base credits to light-duty OEMs.
- There is a sizeable long-term incentive in the LCFS to support out-of-state, out-of-sector dairy manure management projects through book-and-claim crediting for hydrogen projects. CARB should

[1] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/15day_notice.pdf
[2] https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard

implement deliverability requirements for biomethane-derived hydrogen consistent with biomethane-derived RNG and electricity.

These comments focus on substantial changes made to biomass-based diesel (BBD) and jet fuel crediting, reallocation of electricity base credits generated during private charging events, and updates made to direct air capture (DAC), hydrogen, and medium and heavy-duty infrastructure crediting. We also discuss discrepancies and changes to input assumptions in the CATS model that notably differ from previous modeling runs.

Strengthen the Crediting Limit for Vegetable Oil-derived Biomass-Based Diesel

CARB made substantial changes to biomass-based diesel (BBD) crediting guidance in the 15-day package amendments. The revised text now sets a limit on the quantity of BBD derived from soybean and canola oil that can receive LCFS credits. The crediting restriction is applied at the company level and takes effect immediately for newly certified pathways and facilities that blended less than 20 percent of their certified volumes during 2023 LCFS reporting year. For all other facilities, the crediting restriction takes effect in 2028.

The proposed restriction on soybean and canola oil crediting is a commendable step to mitigate the unintended emissions consequences of crop-based fuel production. However, by itself, the proposal will have little effect on the consumption of vegetable oils in U.S. biofuel markets due to loose compliance requirements and likelihood of feedstock shuffling. If other states and neighboring regions such as Canada fail to implement their own crop-based fuel safeguards, it is likely that fuel suppliers will instead sell these products in new markets with little net climate benefit. CARB's proposal also sets a moving target based on annual BBD production rates rather than a total energy-based or volumetric feedstock consumption limit that would be more closely aligned with an estimate of sustainable feedstock availability.[3]

Though the proposed vegetable oil limitation is intended to mitigate the unintended, indirect consequences of the LCFS program on vegetable oil demand, we find that its effectiveness may be limited for several different reasons. First, we find that the proposed treatment of vegetable oils in excess of the proposed limit of 20% by volume still preserves valuable

[3] https://theicct.org/wp-content/uploads/2022/08/lipids-cap-ca-lcfs-aug22.pdf

incentives for their use, diluting the impact of any restrictions. Second, CARB's crediting restriction only applies to soybean and canola oil consumed as BBD, which could incentivize the consumption of other vegetable oils and oilseed cover crops with their own market and environmental risks. As written, the proposal also preserves incentives for soybean and canola oil that are processed into jet fuel. Lastly, we find that design of the grandfathering provisions could allow for a significant expansion of vegetable oil volumes over present-day consumption. We discuss each of these issues in more detail below.

Even with a limit in place, we find that there is still a valuable financial incentive for vegetable oils in the California LCFS. The proposal specifies that soy and canola oil-derived biofuels in excess of the 20% limit would be assigned the benchmark CI rather than the fossil CI, thus not generating any deficits. In addition to LCFS credits, BBD producers that sell fuel in California benefit from a federal tax credit, to be converted into the 45Z tax credit in 2025 and federal Renewable Identification Number (RIN) credits; while refiners benefit from avoided cap-and-trade penalties that apply to petroleum fuel.[4] This corresponds to a net incentive of $2.66 per gallon of soybean oil BBD and $3.33 per gallon of used cooking oil (UCO) BBD sold in 2025, based on the average CI of these feedstock-specific pathways approved under the LCFS. If the CI for excess BBD is instead updated to the CI of fossil diesel, vegetable oil BBD blended in excess of the limit will generate LCFS deficits and dampen the growth trajectories of the riskiest feedstocks. We estimate that this change would reduce the net value of RD sold in California by $0.21/gallon, assuming a $70 per tonne LCFS credit price.[5]

The proposed exclusion of SAF produced from vegetable oils from any crediting restrictions does not have any scientific justification and would undermine the integrity and intention of the limits. Given that the proposed crediting restrictions were drafted in response to concerns over the unintended impacts of the LCFS program's demand for crops on land-use and climate, the end-use sector of said crop-based biofuels is not relevant for the purposes of the safeguard. In other words, whether that soy oil is used in the road sector or the aviation sector is not relevant to the underlying problem posed by the feedstock used to make that biofuel. Further, excluding aviation fuels from these restrictions poses an important risk, as there may be a valuable incentive to blend vegetable oil-derived SAF's in excess of the cap. Combining credit incentives from the LCFS, RINs, and 45Z

[4] https://www.c2es.org/content/california-cap-and-trade/

[5] https://www.neste.com/investors/market-data/lcfs-fuel-standard-credit-price

tax credits, this amounts to approximately $2.30/gallon for soybean oil-derived SAF sold in 2025.[6]

Refiners typically prioritize BBD over SAF production due its lower net production cost.[7] For example, under the 45Z tax credit incentives, UCO receives $0.83/gallon when sold as SAF and $0.48/gallon when sold as renewable diesel, a $0.36 price differential. Renewable diesel receives slightly higher financial incentives than SAF when sold as RIN credits due to its higher energy density and near equivalent incentives when sold on the LCFS credit market. In total, we find that this difference in incentive value is not high enough to overcome SAF's production cost premium of $0.56 per gallon. We estimate this production cost gap based on recent data reported by S&P Global for renewable diesel and SAF produced in Northwest Europe.[8] We display the incentive values for BBD and SAF derived from soybean oil and UCO in Table 1 below.

Table 1. Value of BBD and SAF crediting in California

Fuel	45Z tax credit ($/gallon)	RIN ($/gallon)	LCFS credit ($/gallon)	Avoided Cap & Trade Penalty ($/gallon)	Net incentive ($/gallon)
Used cooking oil					
SAF	$0.83	$1.89	$0.50	N/A	$3.22
BBD	$0.48	$2.01	$0.52	$0.33	$3.33
Soybean oil					
SAF	$0.23	$1.89	$0.18	N/A	$2.30
BBD	$0.13	$2.01	$0.19	$0.33	$2.66

Note: The life-cycle CI values used in this table are calculated based on the average CI of approved HVO and SAF pathways in California. For soybean oil, we replace CARB's ILUC value with the ILUC values used in GREET 2023 to calculate maximum 45Z credit incentives assuming that the 40B default LCA values will carry over to 45Z. RFS RIN values are based on the 2019-2023 average price.

Although the production cost gap between RD and SAF is not expected to change substantially in the future, refineries may alter their product slate to produce higher volumes of SAF to avoid feedstock curtailment once fuel producers approach the vegetable oil cap. Optimizing SAF output could result in over 2 billion gallons of soy and canola-based fuel that is not subject

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[6] We note that under the default configuration of the 40B GREET model, soy oil jet fuel has a GHG reduction higher than that in CA-LCFS, largely due to the use of a much lower ILUC factor.

[7] https://theicct.org/sites/default/files/publications/Alternative_jet_fuels_cost_EU_20190320.pdf

[8] https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/oil/110223-decarbonizing-aviation-passengers-likely-to-shoulder-price-of-saf

to any crediting restrictions, far higher than the potential volume limit on credit generation.[9]

We therefore recommend that the vegetable oil derived BBD beyond the 20 percent limit is assigned the carbon intensity of fossil diesel rather than substituted with the annual CI reduction target; thus, producing neither credits nor deficits. The current amendment text is inconsistent with text for biomass that does not meet third party certification requirements (Section 95488.9(g)(1)) under which biomass that fails to meet minimum sustainability requirements is assigned the CI of fossil diesel.[10] CARB's proposed guidance ensures that soy and canola oil BBD will not generate program deficits above the 20 percent production limit and thus incur no financial penalties when they are sold in the California market. This in turn provides a weak signal to bio-refiners to make meaningful changes to their operations to comply with the annual CI benchmark. Likewise, we recommend that vegetable oil-derived SAF's are treated consistently with road sector fuels, and are not excluded from any crediting restrictions.

We recommend that the 20 percent crediting restriction on these feedstocks should be broadened to include all crop-based BBD to reduce growth in other oilseed crop markets that are linked to their own market-mediated emissions impacts. Setting a narrow definition for vegetable oils as currently proposed could incentivize imports from lesser consumed biofuel feedstocks in the future such as sunflower and peanut oil. Valin et al. estimate that sunflower oil has a LUC value of 63 gCO2e/MJ in their impact assessment that informed the European Renewable Energy Direct (RED).[11] The LUC value of peanut oil has not yet been assessed in major studies or regulations; however, a 2015 study indicates that peanut oil may have a worse environmental performance on a life-cycle basis than other common biofuel feedstocks such as canola and palm oil.[12]

Further, we recommend that the restriction on vegetable oil crediting is introduced under a more accelerated timeframe to strengthen its impact in the near-term. Due to the current grandfathering provision, any BBD producer that blended soybean and canola oil at greater than 20 percent of

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[9] This calculation is based on the combined hydrotreatment capacity in Table 2 below, assuming a 55% SAF share when optimized to maximize SAF output.
[10] CARB proposes to assign the CI of CARBOB to biomass that is processed into ethanol and the CI of ULSD to all other biofuels
[11] Valin, Hugo, Daan Peters, Maarten van der Berg, Stefan Frank, David Havlik, Nicklas Forsell, Koen Overmars, and Carlo Hamelinck. "The Land Use Change Impact of Biofuels Consumed in the EU: Quantification of Area and Greenhouse Gas Impacts," August 27, 2015.
[12] https://www.sciencedirect.com/science/article/abs/pii/S0959652614010518

their certified volumes during 2023 LCFS reporting does not have to adhere to the crediting restriction until 2028. This creates room under the crediting limit for refinery expansion and higher soy and canola blend rates in the interim years.

Rapid refinery expansion over the last several years is projected to keep pace through the end of 2025.[13] This includes capacity expansions at the Martinez and Phillips 66 refineries in California; by the end of 2024, these facilities are anticipated to operate at nameplate capacities of 775 and 808 million gallons, respectively.[14] We calculate what the maximum output of renewable diesel at refineries that currently process soybean and canola oil could be based on California's certified fuel pathway table.[15] We draw refinery nameplate capacity data from the U.S. Energy Information Administration's (EIA) renewable diesel plant database.[16]

We only consider refineries that currently process canola, soybean oil, or a combination of both in our maximum capacity calculations. We adjust the nameplate capacity for bio-refineries by a factor of 95% assuming that 5% of the product slate is sold as light ends that remain exempt from the credit restriction. We make this adjustment because CARB's proposed feedstock cap only applies to biomass-based diesel; thus, capped volumes exclude the share of naphtha and SAF produced as part of the distillate product slate. In total, we calculate that these plants could produce a maximum of 850 million gallons of soy and canola-derived RD once the crediting restriction comes into force (Table 2).

Table 2. Crediting limit at eligible renewable diesel refineries

Facility	Total capacity (million gallons)	Proposed cap, Q1 2024 capacity (million gallons)	Proposed cap, maximum capacity (million gallons)
Phillips 66 Company	808	92.1	153.5
Wyoming Renewable Diesel Company LLC	117	22.2	22.2
Dakota Prairie Refining	192	36.5	36.5

[13] https://www.eia.gov/todayinenergy/detail.php?id=55399
[14] https://biodieselmagazine.com/articles/marathon-martinez-renewables-to-reach-100-capacity-by-year-end; https://investor.phillips66.com/financial-information/news-releases/news-release-details/2024/Phillips-66-Announces-Major-Milestone-in-Production-of-Renewable-Diesel/default.aspx
[15] https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities
[16] https://atlas.eia.gov/datasets/b6327e97caef493d9c74695d420cbc11_245/explore?location=38.619967%2C-116.456270%2C6.26

Wynnewood Refining Company, LLC	121	23.0	23.0
Reg Geismar, LLC	101	5.3	5.3
Chevron Products Company	31	5.9	5.9
Cheyenne Renewable Diesel Company LLC	92	17.5	17.5
Diamond Green Diesel Holdings LLC	537	102.0	102.0
Artesia Renewable Diesel Company LLC	141	26.8	26.8
Martinez Renewables LLC	775	73.7	147.3
Jaxon Energy, LLC	25	4.8	4.8
Montana Renewables, LLC	184	9.6	9.6
St Bernard Renewables LLC	320	60.8	60.8
Diamond Green Diesel Holdings LLC	982	186.6	186.6
Cvr Renewables Wyn, LLC	121	23.0	23.0
Altair Paramount, LLC	42	2.2	2.2
Vertex Renewables Alabama LLC	123	23.3	23.3
Total	4,712	715	850

Similarly, we estimate the feedstock cap for biodiesel (i.e., FAME) derived from existing plants that currently process soybean, canola oil, or a combination of both. We reference capacity data from EIA's U.S. Biodiesel Plant Production Capacity dataset to match the nameplate capacity from U.S. biodiesel plants to fuel producers currently generating LCFS credits in California (Table 3).[17] In total, we calculate that these plants could produce a maximum of 221 million gallons of soy and canola-derived biodiesel.

Table 3. Crediting limit at eligible biodiesel refineries

Facility	Total capacity (million gallons)	Proposed cap, maximum capacity (million gallons)
Biox Canada Limited	227	45.4
Reg Newton, LLC	38	7.6
Reg Danville, LLC	50	10
Global Alternative Fuels, LLC	15	3
Ag Processing Inc	42	8.4

[17] https://www.eia.gov/biofuels/biodiesel/capacity/

Reg Grays Harbor, LLC	107	21.4
Canary Biofuels Inc.	20	4
Reg Albert Lea, LLC	46	9.2
High Plains Bioenergy	40	8
Bioenergy Development Group LLC	36	7.2
Reg Seneca, LLC	76	15.2
Canary Renewables Corp.	20	4
Cargill Biodiesel	56	11.2
World Energy Harrisburg LLC	19	3.8
Ag Processing Inc	76	15.2
Western Iowa Energy	45	9
REG Mason City, LLC	39	7.8
Archer Daniels Midland Co	85	17
ADM Agri-Industries Company	70	14
Total	1,107	221

We estimate that the maximum combined vegetable oil crediting limit is roughly 1,070 million gallons, far higher than our 2022 estimate of soy and canola oil feedstock availability in California in 2030 (approximately 100 million gallons—California's market-adjusted share of the total nationwide soy BBD consumption). That estimate draws upon a 2022 ICCT analysis of U.S. feedstock availability, 2021 soy oil consumption in transport, and applies a factor 7.3% to represent California's share of the distillate fuel market.[18] This volume limit exceeds current consumption of soybean and canola oil-derived BBD in California (roughly 434 million gallons in 2023) that currently accounts for 32% of total vegetable oil-derived BBD volumes.[19] However, because the crediting limit will not come into effect until 2028 for facilities already consuming greater than a 20% share of vegetable oil, there is an opportunity for the consumption of vegetable oils to continue to expand until 2028. For example, the Martinez and Phillips 66 refineries are the two largest in California with a combined theoretical capacity of 1.58 billion gallons, much higher than their current capacity utilization. If they are grandfathered under the crediting proposal and process soybean and canola oil at full capacity, this could push the crediting restriction significantly upwards.

CARB has acknowledged these risks given that its entire diesel fuel pool is larger than the federal RFS renewable volume obligation (RVO) and that other states and provinces have begun to introduce their own clean fuel

[18] https://theicct.org/wp-content/uploads/2022/08/lipids-cap-ca-lcfs-aug22.pdf
[19] https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries

standard programs.[20] These programs are expected to increase competition for resource-limited feedstocks and could reverse the current trend of rapid BBD growth in California. However, if California continues to provide an excess price signal for BBD (and further if the AAM is triggered), limited feedstock resources will continue to flow to the state and could crowd out investment in other lower-carbon technology pathways.

While the proposed restriction on soybean and canola oil crediting is a first step in acknowledging these risks, it does not go far enough to mitigate them. Setting a volume or energy-based cap on the quantity of lipids eligible under the LCFS program would be a far stronger approach in reducing vegetable and waste oil consumption in BBD markets. This approach was taken by Germany in its implementation of the EU RED.[21] Research has found that the indirect land use change (LUC) emissions impacts of vegetable oil feedstocks may be even worse than that of fossil fuels due to market linkages that trigger the conversion of primary forestland or peatland.[22] Though waste oils do not present the same LUC risk, traceability and fraud risk remain a significant concern.

Implement Third-Party Sustainability Certification for Biomass Wastes and Residues

We strongly recommend that CARB expand third-party certification requirements to include biofuels made from wastes and residues. Though the 15-day package expands the certification requirements to include forest biomass, it is unclear if this provision extends to other sources of biomass. Waste oils have made up the largest share of BBD credits since the start of the LCFS program and are incentivized due to their low CI value relative to crop-based fuel pathways. Waste oils are closely linked with reporting fraud, which has been under increasing scrutiny in the U.S. and Europe. EPA is currently investigating two renewable fuel producers for used cooking oil (UCO) fraud and the EU is undergoing similar investigations.[23] A renewed focus on fraud comes after a sharp rise in UCO imports from Asia, which

[20] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/15day_attc.pdf
[21] https://germanlawarchive.iuscomp.org/?p=315
[22] Hugo Valin et al., The Land Use Change Impact of Biofuels Consumed in the EU: Quantification of Area and Greenhouse Gas Impacts (Utrecht, Netherlands: Ecofys, 2015)
[23] https://www.reuters.com/business/energy/us-epa-says-it-is-auditing-biofuel-producers-used-cooking-oil-supply-2024-08-07/; https://www.reuters.com/sustainability/climate-energy/france-germany-urge-tougher-eu-checks-biofuel-imports-fraud-probe-2024-05-31/

grew from 0.4 thousand tonnes to 718 thousand tonnes between 2022 and 2023 alone.[24]

UCO fraud is prevalent due to the difficulty in distinguishing between filtered UCO and vegetable oil during chemical testing. The European Anti-Fraud Office has investigated cases where virgin vegetable oil was fraudulently labeled as UCO to avoid anti-dumping fees and benefit from national-level renewable energy incentives.[25] In 2020, the Dutch company Sunoil forged sustainability certification scheme (SCS) certificates that credited crop-based biofuels as waste-based biofuels.[26] Similar fraud schemes have occurred in the U.S. in early years of the Renewable Fuel Standard (RFS) program where biodiesel producers forged quality tests for UCO biodiesel as well as overstated production quantities that received RIN credits.[27] An ICCT study that compiled data on UCO trade, collection rates, and resource potential in various Asian countries found that UCO exports may already exceed volumes that are plausibly produced and imported.[28] This risk is exacerbated if BBD demand continues to grow due to policy incentives from federal and state-level fuel programs.

The use of third-party auditors such as those approved under CORSIA and the EU Renewable Energy Directive (RED) can help mitigate the risk of reporting and testing fraud; however, they cannot eliminate this risk entirely.[29] However, a third-party certification can still help to improve the integrity of waste oils credited within the LCFS. For example, the RSB certification for advanced biofuels includes detailed requirements for traceability of waste biomass, specifying that 1) collectors and aggregators in the waste supply chain maintain data and a mass balance system to track their material flows, 2) that collectors maintain evidence to track material

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25 https://anti-fraud.ec.europa.eu/system/files/2021-09/olaf_report_2019_en.pdf
26 https://op.europa.eu/en/publication-detail/-/publication/ec9c1003-76a7-11ed-9887-01aa75ed71a1/language-en
27 United States Department of Justice, "Pennsylvania Biofuel Company and Owners Sentenced on Environmental and Tax Crime Convictions Arising out of Renewable Fuels Fraud," news release, October 20, 2020, https://www.justice.gov/opa/pr/pennsylvania-biofuel-company-and-owners-sentencedenvironmental-and-tax-crime-convictions.
28 https://theicct.org/wp-content/uploads/2023/02/US-UCO-potential_fs_final.pdf
29 https://www.icao.int/environmental-protection/CORSIA/Documents/ICAO%20document%2004%20-%20Approved%20SCSs.pdf

back to its point of origin, and 3) that points of origin can be accessed and audited.[30]

Improve and Update ILUC Assessments for Crop-Derived Biofuels

The proposed 15-day changes also indicate that CARB may choose to reassess indirect land use change (ILUC) values for crop-based fuel pathways based on new data or applications for feedstocks and regions that have not yet been assessed.[31] The current ILUC values are based on a 2015 LUC assessment that used the GTAP-BIO and AEZ-EF models with stakeholder input from an expert working group. CARB recognizes that, because the previous LUC assessment was conducted for domestic feedstocks, current values may not represent a conservative estimate of the market-mediated impacts of biofuels. Specifically, these proposed changes are implemented to protect against "a rapid increase in oil crop demand for biofuel production could potentially add pressure to convert forested land or other land types into biofuel crop production."[32]

ILUC values vary widely across the literature; however, clear trends emerge. Vegetable oil feedstocks have the highest LUC impacts when they are grown on high carbon-stock land such as peatland and primary forestland.[33] Due to the prevalence of feedstock substitution, these feedstocks can trigger global land conversion even when they are planted on existing cropland. EPA's recent modeling comparison document finds that the ILUC emissions for soybean biodiesel range between 9 and 280 gCO2e/MJ.[34] If the ADAGE is removed as an outlier, soybean biodiesel LUC emissions range by 49 gCO2e/MJ, more than half the certified CI of fossil diesel in California.

Due to significant modeling uncertainty, adopting more conservative ILUC values can help address the potential for unintended indirect emissions from biofuel demand in the LCFS program. There is a risk that the current set of ILUC values adopted by CARB could underestimate these emissions impacts due to recently challenged modeling assumptions within GTAP-BIO such as the modeling of unmanaged forest land and high rates of yield

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[30] https://rsb.org/wp-content/uploads/2020/06/RSB-STD-11-001-01-010-v.2.1-RSB-EU-RED-Standard-Adv-Fuels.pdf
[31] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/15day_notice.pdff
[32] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf
[33] Hugo Valin et al., The Land Use Change Impact of Biofuels Consumed in the EU: Quantification of Area and Greenhouse Gas Impacts (Utrecht, Netherlands: Ecofys, 2015) https://pure.iiasa.ac.at/id/eprint/12310/1/ Final%20Report_GLOBIOM_publication.pdf;
[34] https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017P9B.pdf

intensification, as explained in our February comments to the proposed LCFS amendments.[35] Similarly, recent research from a contributor to CARB's 2015 ILUC analysis has identified major structural issues associated with the GTAP ILUC model, including the model's use of correlational behavior rather than empirical studies that establish causality and misapplication of these relationships to different geographic regions and functional forms.[36] Berry notes that GTAP predicts low rates of deforestation and high rates of afforestation based on assumptions from a single study that misrepresents real-world economic behavior; thus, the GTAP model highly underestimates forestland conversion and associated ILUC. GTAP also relies on outdated trade data that does not predict the complete effects of US trade policy on global land use. Further, CARB's 2015 analysis is inadequate to assess the risk of ILUC from new feedstocks and production regions.

We encourage CARB to evaluate ILUC emissions for new geographic regions based on empirical data. Updating the LUC values in Table 6 of the regulation could lead to a meaningful change in the BBD compliance trajectory that could be implemented within the existing structure of the LCFS that is not sufficiently addressed under the current proposals. Due to some of the limitations with the GTAP-BIO model that may result in systematic underestimation of ILUC emissions highlighted above, we also recommend that CARB either use a combination of models or use an alternative model in order to generate a more scientifically robust analysis. Examples of a multi-model approach include the 2019 ICAO-CORSIA analysis of ILUC emissions for SAFs[37] and EPA's 2023 model comparison exercise for corn ethanol and soy biodiesel.[38]

Issues in the CATS model that require further evaluation

CARB made updates to its scenario modeling of the ISOR proposal in the 15-day package. It also assessed three uncertainty scenarios with a focus on AAM impacts, zero-emission vehicle (ZEV) adoption and renewable diesel consumption. The largest changes include a higher step-down of the 2025 compliance target from 5% to 9%. Other changes also include increases to

[35] https://www.arb.ca.gov/lists/com-attach/6886-lcfs2024-AmsCZwFjACcAWQJu.pdf
[36] https://www.arb.ca.gov/lists/com-attach/6987-lcfs2024-AXVUPQNgUWsDa1AP.pdf
[37] https://www.icao.int/environmental-protection/CORSIA/Documents/CORSIA_Eligible_Fuels/CORSIA_Supporting_Document_CORSIA%20Eligible%20Fuels_LCA_Methodology_V5.pdf
[38] https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017P9B.pdf

credit generation from fixed-guideway vehicles and changes to the EER for electric forklifts.

While CARB estimates that renewable diesel volumes will grow to more than 3 billion gallons as a result of the CI target step-down that aligns more closely with our own projections modeled in our April 10th workshop comments, we find that none of the updates to the ISOR scenario and data published following the April 10th LCFS workshop make any adjustments to lipid fuel conversion costs or feedstock availability. In our previous comments, we noted that CATS model refinery conversion costs for renewable diesel were far higher than values reported in the literature and market data (roughly $1,000 per ton), and had potentially mistakenly included feedstock cost within the conversion cost. Brown et al. (2020), Witcover and Williams (2020) and Pavlenko et al. (2019) estimate the levelized cost for hydroprocessed fuels, with estimates ranging from approximately $3.50 to $5.50 per gallon, adjusted for inflation.[39] Drawing from the analysis of Pavlenko et al. (2019), we estimated that the non-feedstock conversion costs alone were roughly $300 per ton for soy renewable diesel, suggesting a slight price premium vs. conventional soy biodiesel ($100/ton), but substantially lower than the original assumption.

ICCT's projections for RD growth published in our April workshop comments are consequently higher than CARB's estimates due to adjustments we made to the vegetable and waste oil supply curves and renewable diesel refinery conversion costs.[40] Recent changes to the proposed amendments (i.e., 15-day package) may change this trajectory. Using the same conversion costs and feedstock supply curve as in ICCT's April 2024 comments, we estimate the compliance trajectory of lipid-based biofuel compliance (including SAF's) in response to the central compliance scenario modeled by CARB in the 15-day package. We find that there is overall a higher volume of renewable diesel consumed in the transport sector in the ICCT scenario, due to the lower production costs. Whereas the share of biofuels in the diesel mix peaks at 90% in the CARB proposal in 2025 and then declines, the ICCT scenario reaches 100% BBD blending in 2027 and stabilizes. This suggests

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[39] Nikita Pavlenko, Stephanie Searle, and Adam Christensen, "The Cost of Supporting Alternative Jet Fuels in the European Union." (Washington, DC: ICCT, 2019), https://theicct.org/sites/default/files/publications/Alternative_jet_fuels_cost_EU_2020_06_v3.pdf; Julie Witcover and Robert B. Williams, "Comparison of 'Advanced' Biofuel Cost Estimates: Trends during Rollout of Low Carbon Fuel Policies," *Transportation Research Part D: Transport and Environment* 79 (February 1, 2020): 102211, https://doi.org/10.1016/j.trd.2019.102211; Adam Brown et al., "Advanced Biofuels – Potential for Cost Reduction" (IEA Bioenergy, 2020), https://www.ieabioenergy.com/wp-content/uploads/2020/02/T41_CostReductionBiofuels-11_02_19-final.pdf.

[40] https://www.epa.gov/renewable-fuel-standard-program/final-renewable-fuels-standards-rule-2023-2024-and-2025

that the CARB scenario may still be understating the impact of the proposal on lipid demand, and further, given that the bulk of the growth occurs before 2028, is stimulating demand before the vegetable oil crediting limit tightens.

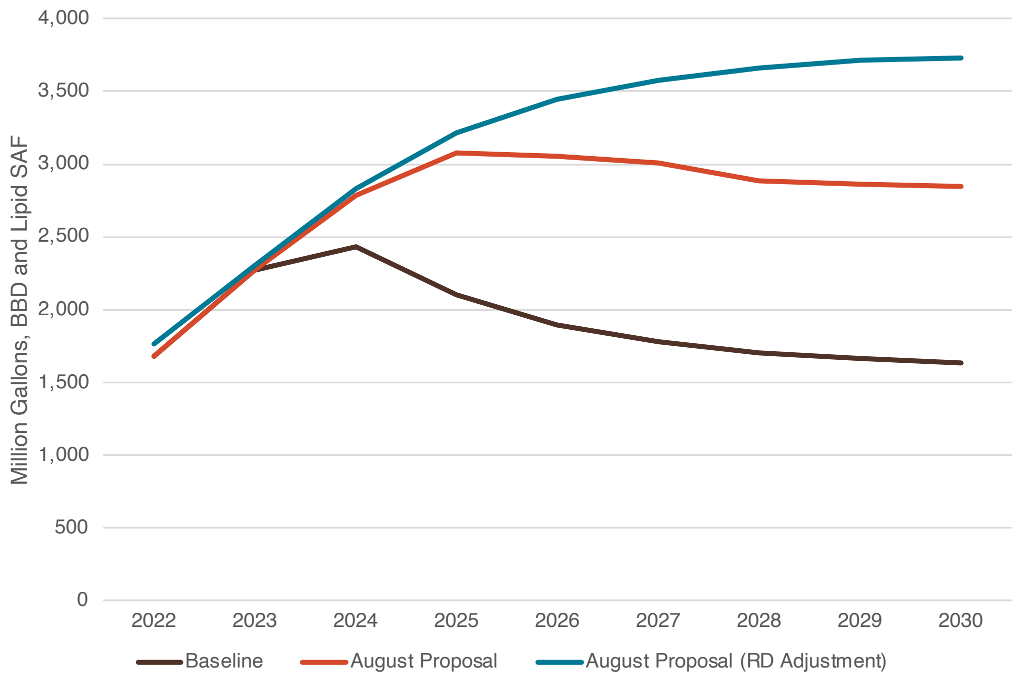

Figure 1: Comparison of Lipid-Based Biofuel Volumes in CARB Baseline + 15-Day Period CATS Scenarios with RD cost & feedstock adjusted ICCT CATS model scenario

We also note several possible errors in CARB's modeling analysis, suggesting that additional analytical work may be necessary to update the model and properly evaluate the proposed 15-day changes. These include several issues:

- The CATS model inputs hard-code substantial increase in SAF deployment despite the removal of the aviation fuel obligation in the LCFS, as well as a simultaneous substantial decline in the benchmark for conventional jet fuel. In the model results, this leads to a decline in the average CI of jet fuel to approximately 74 gCO_2e/MJ by 2030 in the central scenario. The modelers assume that the hard-coded increase in SAF production will come from waste oils, despite the parallel exclusion of virgin vegetable oil-derived SAF's from crediting that is proposed for road sector fuels.
- As noted in our April comments, the model and inputs still do not correctly quantify the treatment of biomethane-derived CNG in the ISOR. Though certified pathways approved prior to 2030 are allowed to be grandfathered for multiple 10-year periods, the quantity of CNG credited abruptly declines to 0 in 2030 in the central scenario.

- The quantity of infrastructure credits is the same between the ISOR and the 15-day package, despite the change from the ISOR.
- There is likely a model or input error for fixed-guideway transit, eCargo Handling Equipment, and refrigeration equipment. Starting in the mid-2020s, the model assumes that the credit generation for these pathways will remain fixed and stays constant each year. However, as the policy benchmark is declining each year, the difference between the electricity CI for these pathways and the benchmark should be narrowing, resulting in fewer credits each subsequent year.

Restore the Proposed Jet Fuel Obligation in the LCFS

CARB's initial proposal to obligate intrastate jet fuel under the LCFS was removed in the recent package, however, CARB is exploring other methods to improve the environmental performance of its aviation sector. This includes regulating mobile source pollutants at large commercial airports, deploying zero-emission buses and ground support equipment, and collaborating with FAA to maintain fleet average NOx emissions and remove lead from aviation gasoline.[41] ICCT supports these complementary activities to reduce the direct air quality impacts of aviation.

While we note that CARB is correct that an obligation on the aviation sector would not itself secure SAF usage, as those deficits could be met with other sources of credits. However, expanding the LCFS obligation to the aviation sector would still provide a meaningful decarbonization signal to the industry by attributing deficits to fossil aviation fuel. Previous ICCT analysis has found that the current, opt-in approach will only motivate small quantities of SAF deployment, far short of California's goals.[42] Additionally, it would also continue the status quo of having the road sector continue to finance the burden of decarbonizing the state's aviation emissions.

To summarize, though we support expanding the scope of the LCFS to include the aviation sector, we caution that it must be done without exacerbating the underlying problems in the LCFS. If aviation is obligated without a separate safeguard on vegetable oils or lipid-based fuels, this could undermine the GHG emission and public health benefits of regulating aviation emissions. Thus, we recommend that CARB obligate jet fuel consumed over the entire CA airspace to spur growth in nascent SAF

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[41] https://ww2.arb.ca.gov/sites/default/files/2024-08/California%20Aircraft%20and%20Airports%20Fact%20Sheet%20-%20July%202024_0.pdf

[42] https://theicct.org/wp-content/uploads/2023/01/ca-aviation-decarbonization-jan23.pdf

markets and deliver public health benefits but only if this obligation is paired with a cap on the consumption of lipid-based fuels. We also recommend that this obligation take effect in 2025 to increase cumulative SAF output and signal earlier support for the production scale-up of advanced fuel pathways.

Implement Deliverability Requirements for Biomethane-derived Hydrogen

The 15-day package does not contain any meaningful deliverability requirements for biomethane-derived hydrogen despite the risk of dilution of the LCFS's signal on supporting out-of-state, out-of-sector manure management projects. In many cases, RNG projects credited under the LCFS are located outside of California that have no direct impact on California's greenhouse gas (GHG) emissions or in-state agricultural practices. In other words, natural gas suppliers may gain revenue from LCFS credits for a unit of fossil gas produced and consumed in California (often in non-transportation uses) with an equivalent unit of renewable natural gas (RNG) produced across the country and injected into the national natural gas transmission grid.

The effect of book-and-claim crediting is particularly egregious for biomethane-derived hydrogen fuel pathways, as these pathways are fully excluded from deliverability requirements until 2046. Producing this hydrogen is a fully mature technology done via steam methane reforming at facilities connected to the existing natural gas grid, drawing upon the grid gas mix, but pairing that hydrogen with a book-and-claim environmental attribute. Despite achieving a higher theoretical credit price than green hydrogen, green hydrogen made from low-CI electricity must satisfy a more rigorous series of requirements than biomethane-derived hydrogen. Electrolytic green hydrogen must ensure deliverability, proof that low-CI electricity comes from new generation, and that there is no double-counting. In contrast, biomethane producers who sell their environmental attributes to existing grey hydrogen producers must only demonstrate the retirement of environmental attributes. Thus, a pathway that enables further use of existing natural gas SMR technology generates higher credit values in the LCFS and has looser book and-claim requirements than a green hydrogen pathway that involves deploying new electrolyzer technology.

The figure below illustrates the LCFS policy value for dairy manure derived hydrogen with a CI of -187 gCO2e/MJ, similar to current certified pathways, across a range of LCFS credit values. These values are compared to the

LCFS value for zero-carbon electrolytic green hydrogen and the red-dotted line indicates the maximum tax credit ($3/kg H_2) that could be received via Inflation Reduction Act's (IRA) Clean Hydrogen Production Credit (Section 45V), which provides tax credits for hydrogen produced with minimal greenhouse gas emissions (below 4kg CO_2e/kg H_2 or 33 gCO_2e/MJ H_2).[43] Dairy biomethane-derived hydrogen could generate a credit value of between $3.3 and $8.8/kg H_2, depending on the LCFS credit price. Even with a conservative credit price of $75/t CO_2e, the policy value for dairy hydrogen surpasses the maximum tax credit a producer could receive from IRA 45V, awarded to low CI hydrogen pathways with GHG emissions less than 0.45kg CO_2e/kg H_2 (3.8 gCO_2e/MJ H_2). Given the high LCFS compliance values shown here, we recommend safeguards for biomethane-derived H_2 to better ensure that this pathway's GHG reductions are attributable to the LCFS and the fuel is being used in the transport sector.

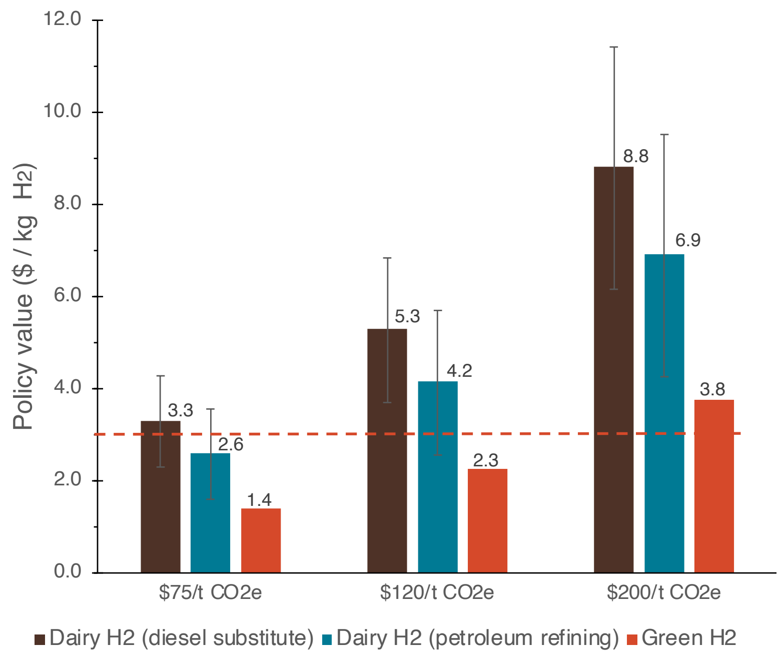

Figure 2. Policy values for dairy biomethane-derived gaseous hydrogen (G.H2) at sample LCFS credit prices estimated using the average CI of LCFS certified pathways. The error bars correspond to the range of CI values from certified pathways. The red line indicates the maximum tax credit ($3/kg H_2) that could be received via IRA's Clean Hydrogen Production Credit (Section 45V).

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[43] Yifan Ding, Chelsea Baldino, and Yuanrong Zhou, "Understanding the Proposed Guidance for the Inflation Reduction Act's Section 45V Clean Hydrogen Production Tax Credit," 2024, https://theicct.org/publication/proposed-guidance-for-the-inflation-reduction-act-45v-clean-hydrogen-tax-credit-mar29/.

Figure 3 below displays the original geographic source of biomethane for certified dairy hydrogen projects in California.[44] Not a single certified biomethane hydrogen pathway in the LCFS actually captures methane in or near California. Based on the lax book-and-claim requirements proposed, we can anticipate there could be significantly more out-of-state farms taking advantage of the LCFS credits in the coming years, with minimal impact on California's transport sector goals or agricultural methane targets.

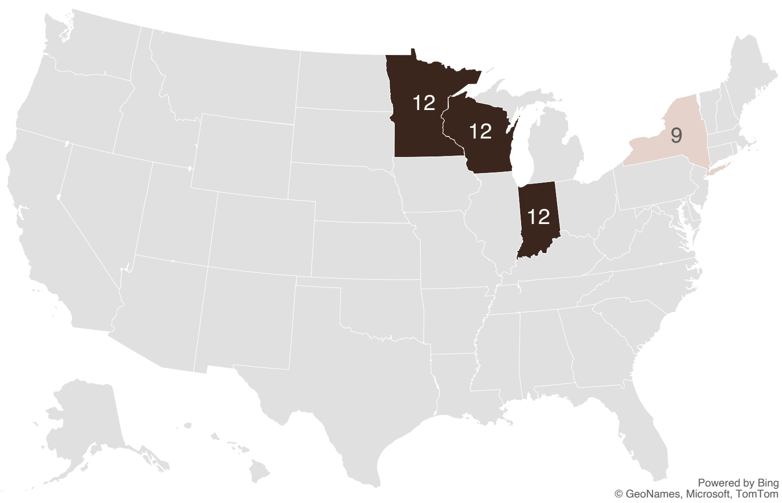

Figure 3. Number of projects and geographic source of dairy biomethane for certified hydrogen pathways in California.

To assess the potential risk from out-of-state farms, we draw upon data from the Census of Agriculture[45] to identify the number of large-scale centralized farms that could be eligible to participate in the LCFS program. In a previous assessment of cost-viable RNG production potential over a 10-year project crediting period, we performed a discounted cash flow analysis and estimated the size of dairy projects that would result in breakeven project cost.[46] Accordingly, a farm should have at least 2,300 dairy cattle to be economically feasible. As the Census data only provides data on certain ranges, we use 2,500 dairy cattle as cut-off. Figure 4 displays the distribution of farms with corresponding dairy cattle numbers indicating the risk for

[44] California Air Resources Board, "Current Fuel Pathways."
[45] U.S. Department of Agriculture, "Census of Agriculture, 2022 Census Volume 1, Chapter 1: State Level," 2024, https://www.nass.usda.gov/Publications/AgCensus/2022/Full_Report/Volume_1,_Chapter_1_State_Level/.
[46] Jane O'Malley, Nikita Pavlenko, and Yi Hyun Kim, "2030 California Renewable Natural Gas Outlook: Resource Assessment, Market Opportunities, and Environmental Performance" (Washington, D.C.: International Council on Clean Transportation, May 22, 2023), https://theicct.org/publication/california-rng-outlook-2030-may23/.

potential out-of-state farms making use of the LCFS crediting system. While California is home to 255 of breakeven farms (31%), there are also a substantial pool of at least 579 out-of-state farms that could qualify for LCFS credits.

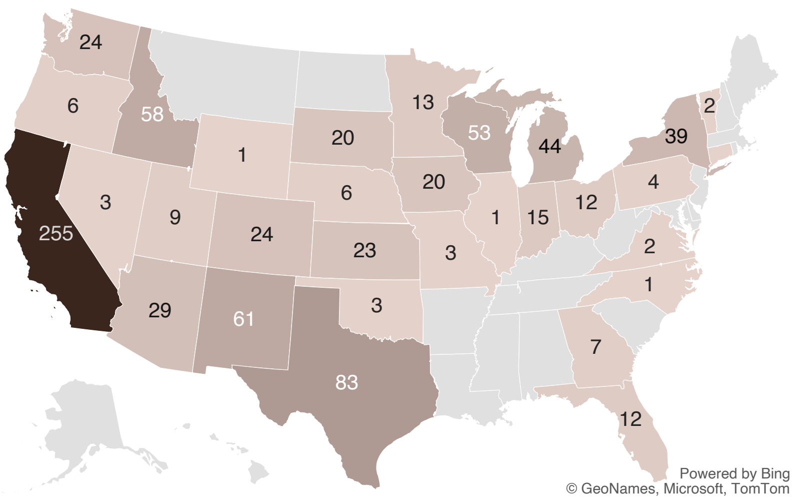

Figure 4. Distribution of dairy farms per state with 2,500 and more dairy cattle.

The Agricultural Census data also reveals that farms with 2,500 or more dairy cattle have increased 17% between 2017 and 2022 in California. Though it is difficult to distinguish causality here, one should also consider the potential risk of consolidation in the industry at the expense of small farms to take advantage of high LCFS credits for RNG.[47] Installing digesters might provide methane reductions when administered properly yet the potential risks should be carefully considered.

The potential of out-of-state farms capturing biogas, and taking advantage of the LCFS crediting is particularly remarkable for the swine industry, which is largely concentrated outside of California. We illustrate this in Figure 5, where we considered farms with greater than 5,000 heads as cut-off since manure per head is lower for swine, and this is the highest range of data available from the Census of Agriculture. Accordingly, there is a total of 3,540 swine farms of this size, and only 2 of them are in California. In this case, the lack of geographical deliverability requirements for biomethane derived hydrogen could lead to an abundance of out-of-state credits generated by an industry without a sizeable in-state counterpart. There are already a few certified pathways for swine manure-derived RNG from Missouri being used as an offset for carbon intensity reductions for hydrogen

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[47] R Lazenby, "Mitigating Emissions from California's Dairies" (Emmett Institute on Climate Change & the Environment, 2024), https://law.ucla.edu/news/mitigating-emissions-californias-dairies-considering-role-anaerobic-digesters.

production in California. These also have similarly low CIs as the dairy farms at an average of -357.4 gCO_2e/MJ of hydrogen.

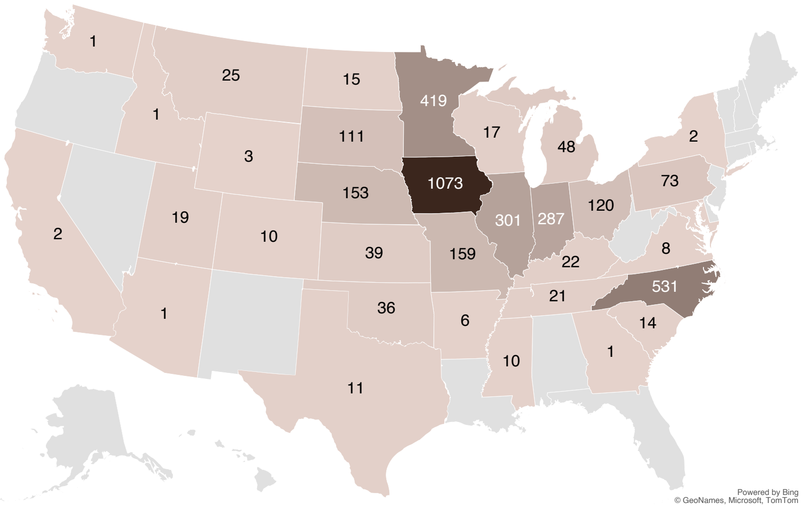

Figure 5. Distribution of swine operations per state with 5,000 and more hogs and pigs.

Thus, there is a possibility that further, long-term loose book-and-claim requirements would largely facilitate deployment of digesters at out-of-state farms with little impact on California's own methane goals or its transport sector emissions. There are hundreds of out-of-state dairy and thousands of swine farms that could take advantage of these incentives. Therefore, we recommend that deliverability requirements for biomethane-derived hydrogen are made consistent with those for biomethane-derived RNG and electricity prior to 2030, in order to prevent this issue from growing and diluting the impact of the LCFS on its transport sector goals.

Attributing Electricity to Direct Air Capture

The proposed changes to the 15-day package loosen the criteria used to attribute low-CI electricity production to direct air capture (DAC) via indirect accounting. Indirect attribution of electricity for producing e-fuels, hydrogen or capturing CO_2 can have unintended emissions consequences, as modeled by Ricks et al. (2023)[48] and highlighted by the U.S. Treasury department in its proposed guidance for the GHG accounting for electrolytic hydrogen.[49] While the exact indirect emissions effects of hourly vs. book-and-claim electricity matching are a source of uncertainty and academic debate for hydrogen production, they are also significant for DAC projects.

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[48] https://iopscience.iop.org/article/10.1088/1748-9326/acacb5
[49] https://www.federalregister.gov/documents/2023/12/26/2023-28359/section-45v-credit-for-production-of-clean-hydrogen-section-48a15-election-to-treat-clean-hydrogen

Due to the intermittency of renewable electricity generation, there is a risk that industrial projects that create demand for electricity outside of the times when intermittent renewables generate electricity will create additional demand for fossil electricity, thus increasing the de facto life-cycle emissions of those projects. Furthermore, California in particular is at risk of large seasonal variation in renewable electricity supply, with a large discrepancy between the total solar generation during the summer months and that generated during winter; this may pose a particular challenge to the integrity of three-quarter book-and-claim attribution given the seasonal renewable electricity imbalance.[50] Thus, annual matching or three quarter matching of environmental attribute certificates (EAC's) from renewable generation from other regions and other times of day to the electricity consumed by those projects may thus systematically underestimate the actual emissions attributable to them.

Because DAC is intended to be a direct source of CO_2 reduction (and is credited as such) in the LCFS, any effects that could affect its net CO_2 balance warrant close scrutiny. Casaban and Tsalaporta (2023) estimate that the energy consumption for a near-term DAC facility under development in Europe requires approximately 500 kWh of electricity and 1500 kWh of waste heat per tonne of CO2 captured based on industry data, with the potential for efficiency improvements such that the energy needs decline to 444 kWh and 1,333 kWh.[51] While the contribution of electricity generated from zero-CI sources under the LCFS would therefore be 0 $kgCO_2e$ per tonne CO2 captured, this could increase significantly depending on the degree to which three-quarter EAC matching diverges from hourly electricity consumption. If we assume that the supplied electricity is the CA grid average of 80.55 gCO2e/MJ in 2024[52], the upstream emissions impact of electricity to provide DAC increases to approximately 145 kgCO2e/tonne CO2 captured. If marginal generating resources are used during off-peak times, as suggested in the electricity sector modeling conducted by Ricks et al. (2023), the natural gas power plant emission factor of 149 gCO_2e/MJ estimated in GREET_2023 may be more appropriate, generating emissions of approximately 268 kgCO2e/tonne CO2 captured. While many DAC LCA's

[50] Mahmoud Y. Abido, Zabir Mahmud, Pedro Andrés Sánchez-Pérez, Sarah R. Kurtz, Seasonal challenges for a California renewable- energy-driven grid, iScience, Volume 25, Issue 1, 2022, 103577, ISSN 2589-0042, https://doi.org/10.1016/j.isci.2021.103577.

[51] Casaban, D., Tsalaporta, E. Life cycle assessment of a direct air capture and storage plant in Ireland. *Sci Rep* **13**, 18309 (2023). https://doi.org/10.1038/s41598-023-44709-z

[52] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/2024_elec_update.pdf?_ga=2.215521363.579411473.1718133376-1766514414.1711042709#:~:text=The%20resulting%20average%20CI%20for,for%20use%20in%202023%20reporting.

assume that zero-CI waste heat is used to supply heat, the use of electricity to generate heat (for example, in a region where waste heat is unavailable or inaccessible) may push the indirect GHG emissions even higher. Taking for example a hypothetical all-electric DAC configuration using heat pumps to supply heat[53], the facility would consume approximately 3.1 times as much electricity for heat & power as electricity alone; this could increase emissions to approximately 450 to 831 kgCO_2e/tonne CO_2 captured using the emission factors above, substantially reducing the net climate benefit for DAC.

Given that relaxing the electricity attribution for DAC can make a substantial impact on the net CO_2 balance for DAC, we recommend restoring the requirement for book-and-claim electricity accounting to quarterly rather than the proposed three-quarter match. Longer-term, in order to mitigate potential unintended emissions, we recommend that CARB implement an hourly matching system for DAC projects, consistent with the approach proposed by Treasury for the 45V hydrogen production tax credit.

Restore the Clean Fuel Reward Rebate Program for Medium and Heavy-Duty Vehicles

The proposed change to base electric vehicle crediting greatly changes the scope and scale of LCFS support for medium and heavy-duty electrification. Whereas the ISOR reserved a significant portion of base credit generation from electrical distribution utilities (EDU's) to be set aside for the Clean Fuel Reward program to fund purchase rebates for the purchase of medium- and heavy-duty ZEV's, that funding is now being set aside for light-duty vehicle OEM's if LDV ZEV sales fall below a threshold of 30% for 2024—a high benchmark designed to be failed. This change constitutes a meaningful blow to CARB's ambition to support the challenging MDHDV electrification transition, which is still in its early stages and which faces stronger barriers than the comparatively more mature ZEV LDV industry.

The proposed changes shift a substantial quantity of funding from MDHDV ZEV's towards LDV with little justification and unclear trade-offs. Based on CARB's modeling outputs in the central scenario, this could amount to approximately 7.5 million credits by 2030 in CARB's central scenario.[54]

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[53] Gutsch, M., Leker, J. Co-assessment of costs and environmental impacts for off-grid direct air carbon capture and storage systems. *Commun Eng* **3**, 14 (2024). https://doi.org/10.1038/s44172-023-00152-6

[54] Based on total electricity consumption in the proposed scenario in the 15-day package CATS modeling, adjusting based on the LDV share of electricity consumption and 45% of credits diverted to OEMs.

Depending on LCFS credit prices, this could range from approximately $375 million to $1.2 billion in value based on an LCFS credit price range of $50-$150, but with far less oversight on how this money would be spent. Examples of allowed activities in the 15-day package include rebates, marketing, installing charging infrastructure, and projects that promote transportation electrification; however, it is unclear how these would be enforced and whether it would lead to meaningful changes to OEM behavior as these are already routine activities. There is also no guidance on how long this credit diversion would remain in place or how money would be allocated across OEM's.

At a minimum, ICCT recommends providing more clear guidance for how this program would be administered, offer a sunset date prior to 2030, and reduce the share of credits reinvested to OEM's. However, given the state of MDHDV ZEV deployment and the need to support California's ambitious Advanced Clean Trucks and Advanced Clean Fleets rules, we recommend restoring the Clean Fuel Reward program and the use of base credits to support MDHDV rebates in order to maximize the effectiveness of the LCFS and use it as a lever to support MDHDV decarbonization.

Changes to Heavy-duty FCI Crediting

Infrastructure crediting is a critical strategy to incentive public fast charger deployment in California to match rapid growth in heavy-duty vehicle (HDV) sales. We support the changes made in the 15-day package to increase ZEV uptake in the medium and heavy-duty vehicle segments, although additional analysis is required.

In its proposed 15-day package changes, CARB loosened restrictions on medium and heavy-duty infrastructure crediting from the ISOR that will provide additional flexibility to charge-point operators to generate LCFS credits. These changes include removing a minimum charger count requirement for HD-FCI applications, extending geographic restrictions to chargers located within 5 miles from Federal Highway Administration Alternative Fuel Corridor, and increasing the total power limit per applicant to 40 MW. We commend CARB for this decision, as it provides more flexibility to deploy charging infrastructure necessary for the electric transition for the MDHDV fleet.

Preliminary ICCT research finds that California will require more than 11,000 medium and heavy-duty vehicle chargers to meet its 2030 charging needs, assuming that the state follows EPA's Phase 3 emissions standard. If

California complies with its Advanced Clean Trucks (ACT) and Advanced Clean Fleets (ACF) regulations that lead to more rapid electric vehicle deployment, charging needs increase to nearly 33,500 medium and heavy chargers. This preliminary research is an update to an analysis published in May 2023 that follows the same study methodology.[55] Recent analysis includes updates to EV stock shares based on MOVES4 and longer overnight charging duration that reduce overall charging needs from earlier estimates.[56] Further analysis is needed to refine the above projections and determine whether the proposed 2.5% cap on MHD-FCI credits should be raised or adjusted to be better aligned with the state's charging needs.

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[55] https://theicct.org/wp-content/uploads/2023/05/infrastructure-deployment-mhdv-may23.pdf

[56] https://www.epa.gov/moves/latest-version-motor-vehicle-emission-simulator-moves