NRDC

June 17, 2022

Liane M. Randolph, Chair
California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

Re: Comments concerning draft scoping plan

To the California Air Resources Board:

Thank you for the opportunity to comment on CARB's Draft 2022 Climate Change Scoping Plan (Draft Plan). Please accept these comments on behalf of Natural Resources Defense Council and its more than 385,000 members, more than 68,000 of whom live in California.

We largely support the set of concerns raised in the environmental organizations' sign-on comment letter submitted June 2, and urge you to consider them. Here, we describe three particular analytical shortcomings in the Draft Plan that we urge you to address, in order to better ensure that the Plan provides a workable and realistic approach to reaching carbon neutrality targets. We are concerned first, that the Draft Plan reflects unjustified optimism in the ability of carbon capture and sequestration (CCS) to address emissions from petroleum refineries. A more genuinely sustainable approach would be to plan in more concrete terms for the phaseout of refining capacity. Second, and similarly, the Draft Plan puts undue reliance in the ability of CCS-equipped hydrogen (or "blue hydrogen") production to reduce the greenhouse has (GHG) emissions. In fact, research demonstrates that blue hydrogen production can, as a result of methane leakage, be more carbon intense than coal. And third, the Draft Plan needs to address more completely and precisely the impact of different types of bioenergy, in particular their potential to cause leakage as defined by AB 32 by increasing GHG emissions outside of California.

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I. The Draft Plan Needs to Significantly Adjust Assumptions Concerning the Role of CCS in Reducing Refinery Emissions

The Draft Plan repeatedly references CCS as a means of reducing GHG emissions from petroleum refining, presenting a figure purporting to show that a scenario in which refineries are equipped with CCS would cut refinery sector emissions by more than half (Figure 2-9). It asserts that newer CCS technologies "can be deployed ..in space constrained and multiple point source facilities such as refineries," and the associated modeling assumes that deployment of CCS at refineries will commence essentially immediately. Draft Plan at 68. But the Draft Plan concedes that implementation in this assumed timeframe is "unlikely," and hence that the modeling for the final Plan will be updated to reflect more realistic assumptions. *Id.*

Simply moving the implementation timeframe for refinery CCS back a few years, however, will not cure the overall analytical flaws in CARB's consideration of refinery CCS in the Draft Plan. Neither sound policy goals nor available evidence supports considering CCS at refineries at all as a means of reducing their GHG emissions. The Draft Plan should define a proactive and comprehensive strategy for the phaseout of combustion fuel refining, rather than merely assuming – contrary to current trends - a correlative decline in refining resulting from declining demand, and looking to mitigate the remaining emissions impacts with CCS. In any case, there is no available evidence that CCS will *ever* be a viable GHG emissions reduction strategy at refineries, and should hence not be considered in the modeling.

The Draft Plan makes the somewhat simplistic assumption that since a measure of continued combustion fuel use will be necessary through 2045, some amount of continued refining will be necessary in that timeframe because the alternative is importation of refined products and attendant emissions leakage. Draft Plan at 68, 79, 81-85. However, the discussion fails to acknowledge that while demand for refined products has fallen modestly in the past decade, refinery output of such products has actually *increased* over the same time period, as refiners increasingly turn to export markets. *See* Table 1. Underlying this situation is the fact that California refining capacity is overbuilt.[1] Hence the refining industry, seeking to protect its otherwise stranded refining assets, has increasingly turned to exports. California refiners exported fully 20% to 33% of statewide refinery production to other states and nations from 2013–2017.[2] West Coast data further demonstrate the strong effect of changes in domestic demand on foreign exports from this over-built refining center.[3] *See* Table 1.[4]

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[1] Karras, 2020. *Decommissioning California Refineries*, available at https://www.energy-re-source.com/decomm.

[2] *Id.*

[3] USEIA, West Coast (PADD 5) *Supply and Disposition;* www.eia.gov/dnav/pet/pet_sum_snd_d_r50_mbbl_m_cur.htm

[4] Table 1 developed by Greg Karras, Community Energy reSource.

Table 1. West Coast (PADD 5) Finished Petroleum Products: Decadal Changes in Domestic Demand and Foreign Exports, 1990–2019.

Total volumes reported for ten-year periods

Period	Volume (billions of gallons)		Decadal Change (%)	
	Demand	Exports	Demand	Exports
1 Jan 1990 to 31 Dec 1999	406	44.2	—	—
1 Jan 2000 to 31 Dec 2009	457	35.1	+13 %	–21 %
1 Jan 2010 to 31 Dec 2019	442	50.9	–3.3 %	+45 %

Data from USEIA, West Coast (PADD 5) *Supply and Disposition*; www.eia.gov/dnav/pet/pet_sum_snd_d_r50_mbbl_m_cur.htm

These factors belie the broad assumption underpinning the Draft Plan that reductions in California demand will lead to a linearly correlated decrease in California refining; and that market forces will ensure that refining levels diminish efficiently. In fact, present data suggest that a decrease in California demand is likely merely to result in continued or even increased refining for the export market. Additionally, refineries that might otherwise close due to excess refining capacity may continue to operate as biofuel producers – as already occurred at the Marathon Martinez refinery[5] – incentivized by subsidies provided via the Low Carbon Fuel Standard (LCFS) (also leading potentially to emissions leakage outside of California as described in Section III below).

The Draft Plan needed to consider all of these real-world market factors in assessing the future of refining in California; and should have used that information to develop a plan to phase out unneeded refining capacity as quickly as possible. The Draft Plan looks to CCS to mitigate refinery GHG emissions through 2045, but fails to actually consider how those emissions could be minimized by developing a proactive plan to wind down combustion fuel refining in the state in an orderly and efficient fashion.

Moreover, while we concur with CARB's recognition that CCS is not presently capable of deployment at refineries, we find no basis to support an assumption that CCS technology will *ever* be sufficiently developed to serve as a feasible solution in the refinery context. Currently, not a single California refinery is retrofitted with CCS; and it is not used comprehensively at any refinery in the world. The 90 percent capture rate assumed in CARB's modeling has no basis in current technological experience at refineries.[6] Deploying CCS at refinery facilities is extraordinarily difficult given the dispersed nature of GHG sources at refining complexes, which include hundreds of combustion stacks from boilers and heaters as well as additional GHG

[5] The Marathon Martinez refinery announced its permanent closure in early 2020, for reasons expressly associated with "consolidation" of its capacity in the Los Angeles area. 2019 Marathon Petroleum Corporation Annual Report. *See* "From the Chairman and CEO" at p. 1. The decision to instead convert the refinery to renewable diesel production was made some months after that announcement.

[6] The Quest CCS project in Alberta, after initially claiming a 90% capture rate, is now only expected to capture on 40% from the refinery as a whole. https://www.shell.ca/en_ca/media/news-and-media-releases/news-releases-2021/shell-proposes-large-scale-ccs-facility-in-alberta.html

emissions from piping and storage tanks. While the Draft Plan makes passing and uncited reference to "new technologies" that can be deployed in modular configurations and space-constrained environments, it offers no basis to conclude that such purported innovations will be either technologically or economically feasible at refineries any time in the foreseeable future.[7] The Plan's unsupported optimistic assumptions about refinery CCS are particularly problematic given recent studies and other available information indicating that the potential for cost-effectively deployment of CCS at refineries is inherently limited by their configuration, and further hampered by the "parasitic load" of energy required to operate CCS.[8]

An assumption of any use of CCS at California refineries would be credible only in the context of much more complete analysis than what CARB has thus far provided. The analysis should include first, modeling of the number and size of refineries that will remain operational through 2045 – *i.e.,* analysis of whether production will be consolidated in a few refineries as consumption winds down as opposed to operation at reduced capacity at many refineries; since deployment of CCS at a refinery operating significantly below capacity may pose additional economic challenges. This analysis of refinery capacity and potential consolidation should take into account the likelihood of continuing or increased refined product exports. Second, the modeling should make conservative assumptions regarding the cost of CCS retrofits, in light of existing studies of such costs, and determine the extent to which retrofits are realistic and likely. Third, the analysis should consider California-specific constraints on deployment of CCS, including, *e.g.*, geological constraints on sequestration, the need to construct CO_2 pipelines through potentially populated areas, and the need to ensure that the captured carbon is not used in enhanced oil recovery (the only current large-scale commercial use for captured CO_2), which would have the effect of creating additional GHG emissions. Finally, and most importantly, the analysis should not assume levels of GHG emissions reductions at refineries achieved via CCS that are greater than levels currently achieved absent clear research indicating a likelihood of more complete emissions capture on a defined timeframe.

Based on currently available data, there is a high likelihood that such analysis would reveal CCS deployment at refineries to be economically and technically infeasible for all intents and purposes. In such case, CARB should re-focus on defining a path toward decommissioning refineries entirely. To the extent that CCS plays any role in the analysis of refinery emissions at all, the start date for any assumption of CCS-related emissions reductions should be pushed at least a decade into the future in light of significant limitations of the current technology.

II. The Draft Plan Should Not Reference Blue Hydrogen as a Potential Source of Zero Carbon Energy

The Draft Plan asserts that "[i]f steam methane reformation is paired with CCS, the hydrogen produced could potentially be zero carbon." Draft Plan at 69. This statement is misleading at best. Unless "potentially" is interpreted to mean purely hypothetically and without basis in practical reality – not a useful framing for climate planning – it contravenes studies and

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[7] Comment submitted by Wara, Michael et al, https://www.arb.ca.gov/lists/com-attach/65-sp22-modelresults-ws-BWQFcVMwUFxWI1Az.pdf.

[8] *Id.*

information indicating that SMR outfitted with CCS, or "blue hydrogen," can be highly emitting on a lifecycle basis at high methane leakage rates.

In the first instance, current CCS technology has not been demonstrated in any context beyond 90 to 95 percent, preventing blue hydrogen from being categorized as "zero carbon." The larger problem, however, is that of methane leakage associated with the production and transportation of methane gas serving as the feedstock for SMR.[9] A recent study[10] concluded that at high methane leakage rates, blue hydrogen is more carbon intense as an energy source than coal, as illustrated in this figure from the study:

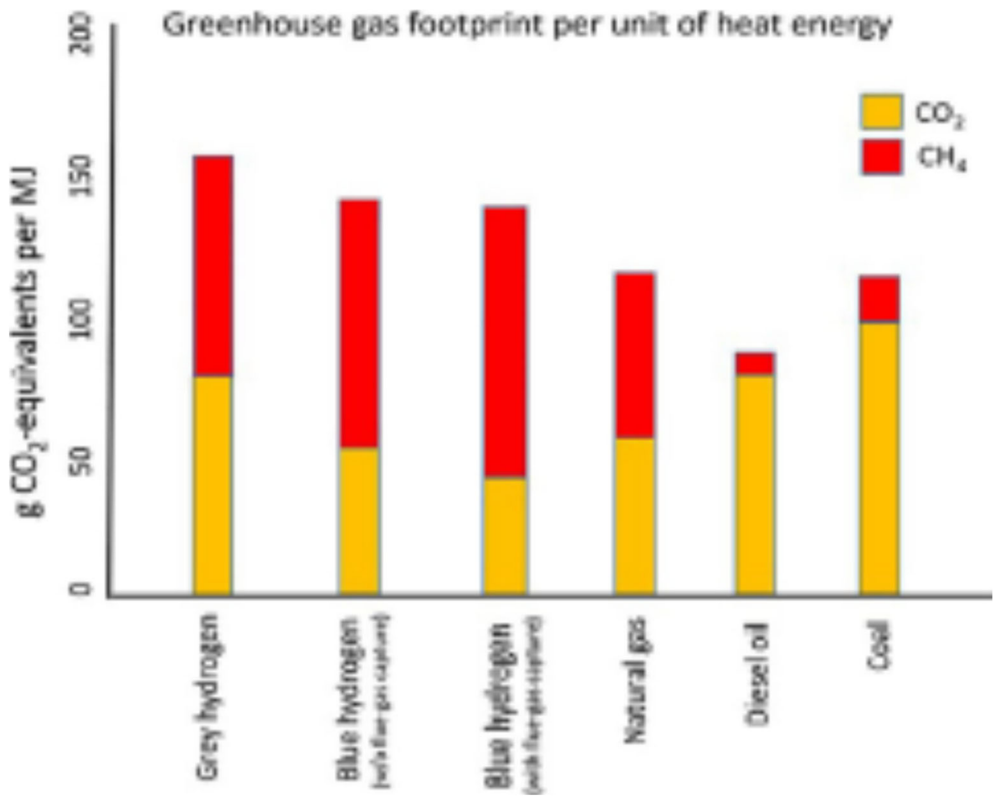

FIGURE 1 Comparison of carbon dioxide equivalent emissions from gray hydrogen, blue hydrogen with carbon dioxide capture from the SMR process but not from the exhaust flue gases created from burning natural gas to run the SMR equipment, blue hydrogen with carbon dioxide capture from both the SMR process and from the exhaust flue gases, natural gas burned for heat generation, diesel oil burned for heat, and coal burned for heat. Carbon dioxide emissions, including emissions from developing, processing, and transporting the fuels, are shown in orange. Carbon dioxide equivalent emissions of fugitive, unburned methane are shown in red. The methane leakage rate is 3.5%. See text for detailed assumptions.[11]

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[9] Dennis Y.C. Leunga, Giorgio Caramannab M. Mercedes, Maroto-Valerb, An overview of current status of carbon dioxide capture and storage technologies, November 2014, Science Direct, https://www.sciencedirect.com/science/article/pii/S1364032114005450

[10] Robert W. Howarth and Mark Z. Jacobson, How green is blue hydrogen? *Energy Sci Eng.* 2021:00:1-12, https://www.actu-environnement.com/media/pdf/news-38015-etude-energy-science-engineering-hydrogene-bleu.pdf (Howarth and Jacobson 2021)

[11] *Id.*

Thus, there is no basis to conclude that blue hydrogen can plausibly be considered a zero-carbon form of production. Nor can it be considered a low carbon source until and unless CARB demonstrates that the methane leakage problem will be resolved.

III. The Scoping Plan Should Address the GHG Impacts of Ramping Up Production of Non-Petroleum Combustion Fuels

The Draft Plan references the LCFS as the primary mechanism for displacement of fossil fuels through subsidies for renewable diesel, sustainable aviation fuel, and other non-petroleum sources of liquid combustion fuel. Draft Plan at 153. The Draft Plan modeling makes a number of assumptions concerning the role of these fuels generally in decarbonization – e.g., that sustainable aviation fuel will meet a large percentage of demand by 2045, and that "liquid biofuel" will increasingly replace liquid petroleum fuel. Draft Plan at 58, 153.

This limited set of assumptions does not address, however, the significant potential of certain types of non-petroleum fuels, generated with particular types of lipid feedstocks in the food system, to increase global GHG emissions through indirect land use change (ILUC) when deployed at very large scale, as is already poised to occur. Additionally, the Draft Plan does not consider available evidence demonstrating that ramp-up of non-petroleum combustion fuels is currently *not* replacing petroleum based fuels, but rather resulting in increased exports of such fuels, thus causing leakage as defined by AB 32 ("a reduction in emissions in greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state").

With respect to ILUC, it is likely that the majority of renewable diesel and sustainable aviation fuel produced in the state will come from food crop and food system oils, predominantly soybean oil. One indicator for the likely predominant role of SBO and other food crop oils for future liquid fuel production is the current breakdown of feedstock demand for biodiesel production.[12] From 2018 to 2020, 59% of biodiesel in the United States was produced from soybean oil as feedstock, compared to 11% from yellow grease, 14% from distiller's corn oil, and only 3% from tallow, or rendered beef fat.[13] Another indicator is the limited domestic supply of alternative feedstock sources. Tallow and other waste oil volumes have come nowhere near meeting current biodiesel feedstock demand, with little prospect of expanding soon.[14]

There is now broad consensus in the scientific literature that increased demand for food crop oil biofuel feedstock has induced ILUC, with significant negative climate and other

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[12] *See* Zhou, Y; Baldino, C; Searle, S. *Potential biomass-based diesel production in the United States by 2032*. Working Paper 2020-04. International Council on Clean Transportation, Feb. 2020, https://theicct.org/sites/default/files/publications/Potential_Biomass-Based_Diesel_US_02282020.pdf (accessed Dec 8, 2021).

[13] Uses data from EIA Biodiesel Production Report, Table 3. Feedstock breakdown by fat and oil source based on all data from Jan. 2018–Dec. 2020 from this table. U.S. Energy Information Administration (EIA), Monthly Biodiesel Production Report Table 3, Feb. 26, 2021, https://www.eia.gov/biofuels/biodiesel/production/table3.pdf (accessed Dec. 14, 2021). Data were converted from mass to volume based on a specific gravity relative to water of 0.914 (canola oil), 0.916 (soybean oil), 0.916 (corn oil), 0.90 (tallow), 0.96 (white grease), 0.84 (poultry fat), and 0.91 (used cooking oil). See also Zhou, Baldino, and Searle, 2020-04.

[14] *See* Baldino, C; Searle, S; Zhou, Y, *Alternative uses and substitutes for wastes, residues, and byproducts used in fuel production in the United States*, Working Paper 2020-25, International Council on Clean Transportation, Oct. 2020, https://theicct.org/sites/default/files/publications/Alternative-wastes-biofuels-oct2020.pdf (accessed Dec 8, 2021).

environmental consequences.[15] The European Union is poised to respond with curbs on such feedstocks. After a decade of studies, soybean oil will likely be designated a high-ILUC risk biofuel that will be phased out of European Union renewable energy targets by 2030.[16] Belgium has already banned soybean oil-based biofuels as of 2022.[17] The ILUC is substantially a result of displacement and substitution of commodities, leading to the conversion of land use for crops other than that of the feedstock demanded. Since oil crops are to a great degree fungible—they are, essentially, interchangeable lipid, triacylglycerol (TAG) or fatty acid inputs to products[18] -- their prices are significantly if not wholly linked: when the price of one crop increases, another cheaper crop will be produced in greater volumes to fill the gap as consumers substitute their use of the more expensive crop. A chief substitute for soybean oil is palm oil, whose production has been linked to significant deforestation and associated carbon sink loss.

While the LCFS of course considered ILUC in assigning carbon intensity (CI) scores to renewable fuels produced with various feedstocks, CI is by nature a measure of incremental per unit impact, not designed to assess the displacement impact that occurs when a very large share of food crop oils becomes dedicated to energy production, hence incentivizing cultivation of additional palm oil to take the place of these food crop oils. The GHG impact of a large-scale movement toward bioenergy has thus not been fully evaluated; but in light of highly problematic current trends, Europe is nonetheless taking the lead in curbing that impact through prohibitions on the feedstock most clearly driving ILUC-related GHG impacts. CARB, rather than making generalized and unsupportable assumptions regarding the role of bioenergy in decarbonization, should evaluate the possibility of doing the same.

With respect to leakage, available data shows that petroleum distillate fuels refining for export continued to expand in California in the last two decades even as biofuel production ramped up in recent years. It is clear from this data that renewable diesel production during those decades -- originally expected to replace fossil fuels – actually merely added a new source

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[15] *See* Portner et al., 2021; C. Malins and C. Sandford, *Animal, vegetable or mineral (oil)? Exploring the potential impacts of new renewable diesel capacity on oil and fat markets in the United States*. Cerulogy, ed. International Council on Clean Transportation, Jan. 2022. https://theicct.org/wp-content/uploads/2022/01/impact-renewable-diesel-us-jan22.pdf. *See also* Searchinger, T. et al., *Use of U.S. Croplands for Biofuels Increases Greenhouse Gases Through Emissions from Land Use Change*. Science, 2008, 319, 1238, https://science.sciencemag.org/content/319/5867/1238 (accessed Dec 8, 2021) (This landmark article notes one of the earliest indications that certain biofuel feedstocks are counterproductive as climate measures.)

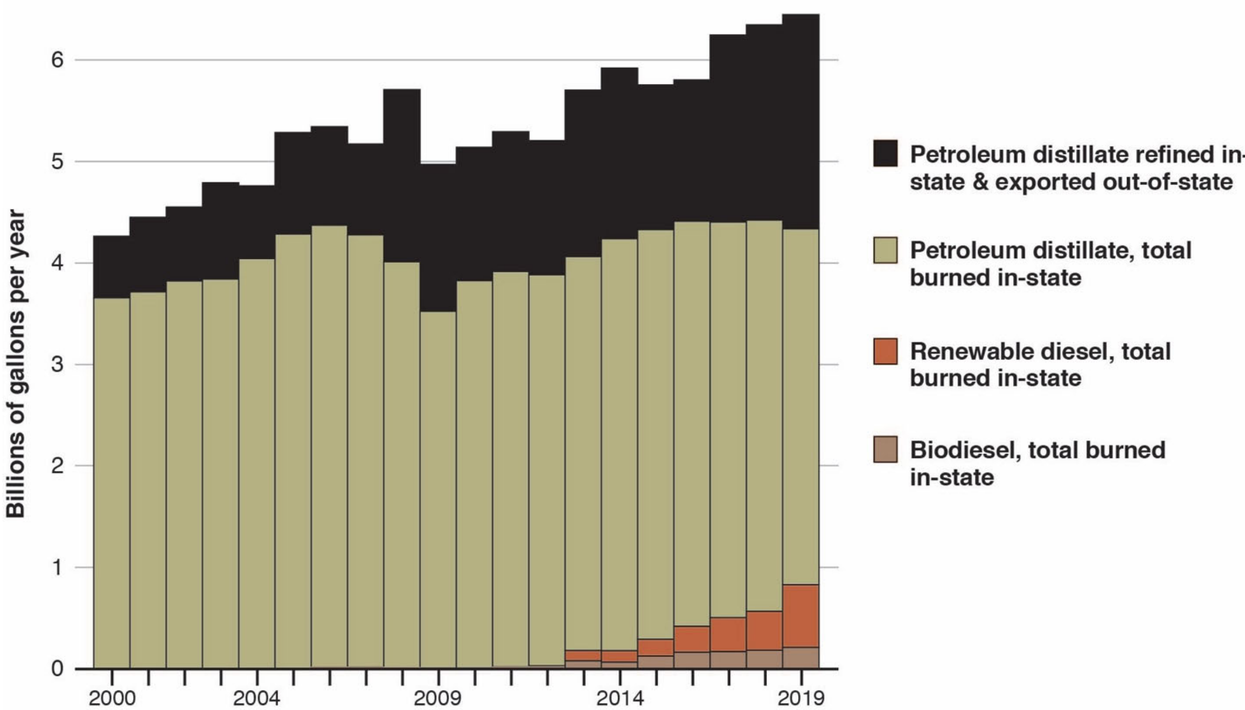
[16] Malins, C. *Risk Management: Identifying high and low ILUC-risk biofuels under the recast Renewable Energy Directive*; Cerulogy, 2019; 4, 14. http://www.cerulogy.com/wp-content/uploads/2019/01/Cerulogy_Risk-Management_Jan2019.pdf (accessed Dec 8, 2021).

[17] Belgium to ban palm- and soy-based biofuels from 2022. Argus Media, Apr. 14, 2021. https://www.argusmedia.com/en/news/2205046-belgium-to-ban-palm-and-soybased-biofuels-from-2022 (accessed Dec 8, 2021).

[18] The Environmental Impact Report (EIR) for the Rodeo Renewed biofuel conversion project expressly recognized this fungibility: “The different uses of the commodity and whether or not there are substitutes for those commodities also affect the renewable feedstocks market. For example, soy and corn can both be used for livestock feed or human food production. If one commodity increases in price, farmers may be able to switch to the other commodity to feed their livestock for a cheaper cost (CME Group). This is particularly important for renewable feedstocks given the different uses for oilseeds, including food production and animal feedstocks, and the different vegetable oils that may be used as substitutes (e.g., canola oil may be a substitute for soybean oil).” Rodeo Renewed Final EIR 3.8.3.2.

of carbon to the liquid combustion fuel chain. Total distillate volumes, including diesel biofuels burned in-state, petroleum distillates burned in-state, and petroleum distillates refined in-state and exported to other states and nations, increased from approximately 4.3 billion gallons per year to approximately 6.4 billion gallons per year between 2000 and 2019.[19] [20]

Specifically, crude refining for export – shown in black in the figure below[21] – expanded after in-state burning of petroleum distillate (shown in olive) peaked in 2006, and the exports expanded again from 2012 to 2019 with more in-state use of diesel biofuels (shown in dark red and brown). From 2000 to 2012 petroleum-related factors alone drove an increase in total distillates production and use associated with all activities in California of nearly one billion gallons per year. Then total distillates production and use associated with activities in California increased again, by more than a billion gallons per year from 2012 to 2019, with biofuels accounting for more than half that increment. These state data show that diesel biofuels did not, in fact, replace petroleum distillates refined in California during the eight years before the Project was proposed. Instead, producing and burning more renewable diesel *along with* the petroleum fuel it was supposed to replace emitted more carbon.



Distillate fuel shares associated with all activities in California, 2000–2019.
Growth in total distillates excluding jet fuel and kerosene from State data.
Data from CEC Fuel Watch and CARB GHG Inventory Fuel Activity Data, 2019 update.

Clearly, more analysis is needed before CARB can plausibly treat non-petroleum combustion fuel categorically as a viable strategy to reduce GHG emissions in the transportation

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[19] CARB GHG Inventory Fuel Activity data, 2019 update.
[20] CEC *Fuel Watch*. Weekly Refinery Production. California Energy Commission: Sacramento, CA. https://ww2.energy.ca.gov/almanac/petroleum_data/fuels_watch/output.php
[21] Figure produced by Greg Karras, Community Energy reSource.

sector. Drawing valid conclusions in this regard would require modeling the impact of various renewable feedstocks deployed at varying scales, accounting for the ILUC impacts of such feedstocks in all scenarios associated with fungibility and displacement. It would also require accounting for the AB 32 leakage of emissions through refined petroleum products export, which has thus far resulted in an overall increase in worldwide combustion fuel use and associated GHG emissions.

Through and as a result of such analysis, CARB should commit to reviewing and revising the LCFS to address the potential unintended consequences of deployment of particular types of bioenergy production at very large scales – as is already being proposed at two Bay Area refineries. In particular, CARB should commit to considering caps on LCFS subsidies for particular feedstocks such as soybean oil that have been shown to be particularly problematic as a driver of deforestation.

Thank you for considering these comments.

Very truly yours,

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