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THE INTERNATIONAL COUNCIL ON CLEAN TRANSPORTATION

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May 10, 2024

RE: International Council on Clean Transportation comments on the **April 10th LCFS Workshop**

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 Low Carbon Fuel Standard amendments. We commend the agency for its continued engagement 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. New analysis is based on the content presented in the April 10th workshop including modifications to the California Transportation Supply (CATS) model. 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).

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Summary of comments

The California Air Resources Board (ARB) presented additional analysis on their 45-day Low Carbon Fuel Standard (LCFS) proposal at their public workshop held on April 10th.[1] Staff reviewed different compliance trajectories to align the program with the 2022 Scoping Plan that were first presented in the December 2023 Initial Statement of Reasons (ISOR) report.[2] These include the proposed scenario ("45-Day Proposal"), Environmental Justice Advisory Committee (EJAC) scenario, and scenarios that include less and more stringent CI reduction trajectories. At the latest workshop, other adjustments were made to ISOR modeling including an updated feedstock supply curve for virgin and waste oils, updated combustion emission factors, and varying step-down rates in 2025 that maintain the proposed 30% CI reduction target in 2030.

Though ARB discusses the sustainability risks of biomass-based diesel in its 45-Day Proposal, the impact of its proposed sustainability certifications has not been modeled by ARB and there is no evidence that it will demonstrably mitigate growth in unsustainable compliance pathways. In these comments, we evaluate the scenarios and data released by ARB for the April workshop and compare it to program and market data. We compare the real-world growth of biomass-based diesel (BBD) and projected capacity announcements to ARB's various modeled compliance scenarios. We review these assumptions and re-run the CATS model to project likely fuel volumes using an updated feedstock supply curve and conversion costs below.

In these comments, we also evaluate the proposed changes to the LCFS on the program's inclusion of dairy biomethane-derived hydrogen, and the impact of the proposed set of deliverability requirements. We assess the potential for out-of-state digester projects to dilute the program's intended impact on in-state methane emissions and transportation emissions goals.

We find that the discrepancies between ARB's modeled scenarios and recent real-world data on BBD production are large and that ARB's scenarios are not credible. When we rerun ARB's model using updated data inputs, we find the proposed LCFS amendments will drive over a 600 million gallon to 1 billion gallon increase in BBD consumed in California relative to present-day consumption, which could cause unintended GHG emissions land use change and deforestation globally, undermining the intended impacts of the program. We also find that out-of-state biomethane production will significantly dilute the effectiveness of the LCFS in delivering genuine in-state GHG reductions.

Based on our technical analysis, we recommend that ARB:

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[1] ARB, "California LCFS Workshop," https://ww2.arb.ca.gov/sites/default/files/2024-04/LCFS%20April%20Workshop%20Slides.pdf.
[2] ARB, "Staff Report: Initial Statement of Reasons," Public Hearing to Consider the Proposed Amendments to the Low Carbon Fuel Standard, December 19, 2023.

1. Address gaps in existing LCFS compliance modeling to evaluate the impact of more recent data on lipid supply and renewable diesel conversion costs on the potential market impacts and virgin vegetable oil demand of the LCFS.
2. Implement a cap on the volume of lipid-derived fuels credited under the LCFS program.
3. For all new biomethane-derived hydrogen pathways, implement geographic deliverability requirements within the next three years.

Review of ARB ISOR scenarios

The set of updated scenarios shared by ARB at the April LCFS workshop shed light on possible growth trajectories for biomass-based diesel (BBD), one of the fastest growing fuel pathways under the LCFS program. In 2023, BBD made up 61% of LCFS credits, up from only 8% in 2011.[3] Renewable diesel capacity deployment in California has consistently exceeded predictions by the Energy Information Administration (EIA).[4] Indeed, Murphy and Ro already updated their 2023 LCFS volume projections to account for higher-than-anticipated renewable diesel output and 1.7 billion gallons in additional nameplate capacity refinery conversions slated for this year.[5]

Evaluating the modeled projections for the program compliance under the LCFS revisions shared by ARB staff in April, it is clear that there is disagreement between the projections and the real-world data reported by ARB through 2023, as well as with the pace of renewable diesel capacity expansion in the U.S. reported by the EIA.[6] Figure 1 below compares the reported volumes of renewable diesel consumed in California (shown in solid black) and the national-level, existing and announced renewable diesel capacity expansions to ARB's modeled scenarios (shown by the dotted line). Despite the significant drawdown of credits from the step-change and increase in compliance target, the scenarios modeled by ARB all project that renewable diesel consumption will abruptly stop growing starting in 2024, despite continued real-world expansion in refinery capacity to nearly 6 billion gallons by 2025. Based on this, we note that the scenarios may be structurally underestimating the program's impact on renewable diesel demand and therefore understating the risk of continued pressure on vegetable oil markets.

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[3] ARB, "Low Carbon Fuel Standard Reporting Tool Quarterly Summaries," accessed May 8, 2024, https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries.
[4] U.S. EIA, "U.S. Renewable Diesel Capacity Could Increase Due to Announced and Developing Projects," July 29, 2021, https://www.eia.gov/todayinenergy/detail.php?id=48916.
[5] Colin Murphy, "Updated Fuel Portfolio Scenario Modeling to Inform 2024 Low Carbon Fuel Standard Rulemaking," 2024, https://doi.org/10.7922/G25719BV.
[6] U.S. Energy Information Administration, "Domestic Renewable Diesel Capacity Could More than Double through 2025," February 2, 2023, https://www.eia.gov/todayinenergy/detail.php?id=55399.

In particular, we highlight that the scenario in orange (which contains the auto-acceleration mechanism) increases credit prices significantly by raising the program's ambition to a 39% target by 2030, yet it barely exceeds 2023 reported renewable diesel volumes, essentially limiting future growth of renewable diesel despite rapid increases in supply. In that scenario, credit prices increase rapidly to the cap of $221/ton without a concurrent increase in renewable diesel consumption above present-day levels.

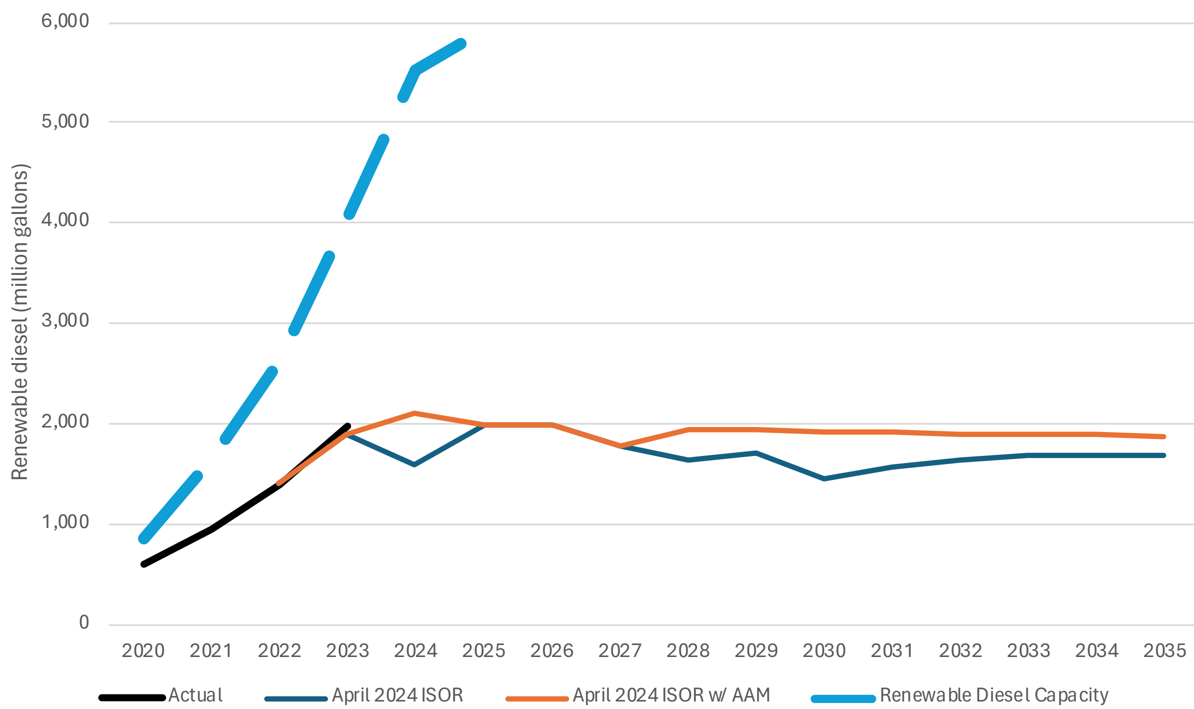

Figure 1: Actual and projected renewable diesel consumption compared to announced capacity

In the subsequent section, we adjust the CATS model developed by ARB to incorporate updated price and availability data for renewable diesel in order to evaluate the risk posed by the program of expanding reliance on soy oil.

Updates to LCFS compliance input assumptions

ARB presented updated supply curves for virgin vegetable and waste oils in their April 10th workshop slides. They report the availability of vegetable oils to be 8.4 million tons while the availability of waste oils is 5.8 million tons based on data calculated from EIA biofuel production reports.[7] Given that there is 13.6 million tons of soybean oil consumed in the U.S. today and this quantity is only anticipated to grow due to increased crushing capacity,[8] ARB's data likely underestimates the availability of soybean oil as a BBD feedstock.

We develop our own supply curves by sourcing annual cost and supply data for soybean oil, yellow grease (i.e., used cooking oil), and tallow from the U.S. Department of Agriculture (USDA) Oil Crops Yearbook tables[9]. We consider the total quantity of soybean oil consumed in the U.S. rather than the quantity consumed in BBD due to the likely diversion of soybean oil from existing markets to the BBD sector to meet rising demand. Since the Oil Crops Yearbook does not report data on yellow grease consumption, we estimate this volume by converting the total volume of waste oil BBD consumed under the Renewable Fuel Standard (RFS) program[10] to tons of feedstock assuming a conversion factor of 0.123 gallons of BBD per pound of waste oil.[11] Based on this dataset, the slope of our supply curve is slightly steeper for vegetable oils and flatter for waste oils compared to the input data used by ARB in their own modeling (Figure 2). This indicates that vegetable oil production is more responsive to changes in price while waste oil supply is similar to ARB's assumptions. Both of our supply curves are also shifted upward; thus, for a given feedstock price, a higher volume of feedstock is supplied relative to ARB's modeling.

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[7] U.S. Energy Information Administration, "U.S. Total Biofuels Operable Production Capacity," April 30, 2024, https://www.eia.gov/dnav/pet/pet_pnp_capbio_dcu_nus_m.htm.
[8] U.S. Department of Agriculture, "Grains and Oilseeds Outlook for 2024" (Oilseeds, Feed Grains, Wheat, and Rice Interagency Commodity Estimates Committees, February 15, 2024), https://www.usda.gov/sites/default/files/documents/2024AOF-grains-oilseeds-outlook.pdf.
[9] "USDA ERS - Oil Crops Yearbook," accessed May 8, 2024, https://www.ers.usda.gov/data-products/oil-crops-yearbook/oil-crops-yearbook/.
[10] US EPA, "RINs Generated Transactions," Other Policies and Guidance, https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rins-generated-transactions.
[11] Hui Xu et al., "Life Cycle Greenhouse Gas Emissions of Biodiesel and Renewable Diesel Production in the United States," *Environmental Science & Technology* 56, no. 12 (June 21, 2022): 7512–21, https://doi.org/10.1021/acs.est.2c00289.

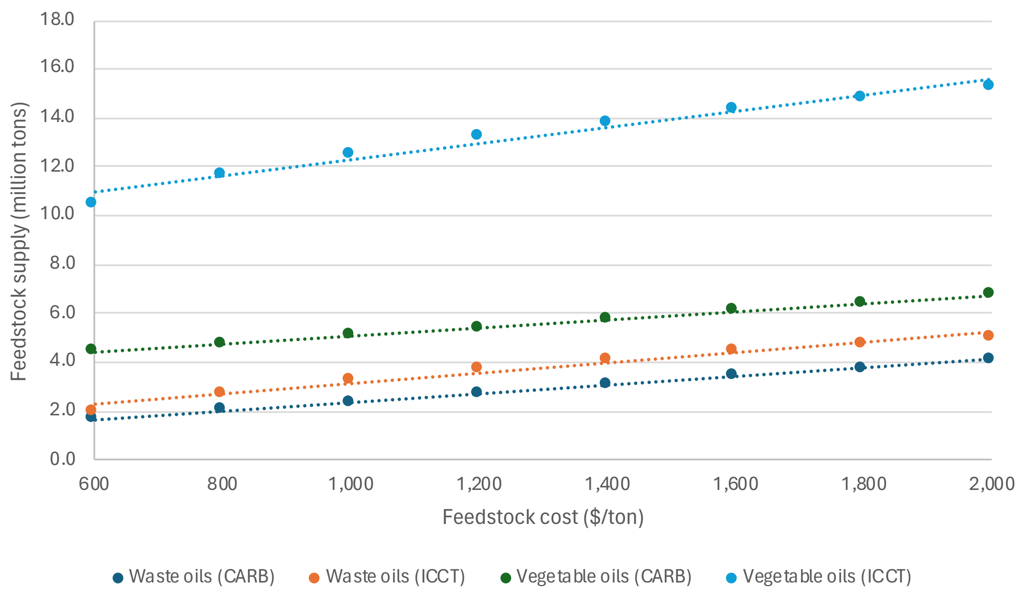

Figure 2: Feedstock supply curve comparison

We also update the conversion costs for renewable diesel and hydrotreated esters and fatty acid (HEFA) facilities, using real-world data. ARB's CATS modeling assumes that renewable diesel has a conversion cost of $925-1122 per ton, significantly higher than the assumed FAME biodiesel conversion cost of $106-383/ton in the model. This is inconsistent with the scientific literature as well as market data, which together suggest a lower production 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.[12] In these studies, the cost of hydroprocessed fuels was driven primarily by feedstock prices, particularly at higher facility scales which benefit from economies of scale for CAPEX. Drawing from the analysis of Pavlenko et al. (2019), we estimate that the non-feedstock conversion costs alone were roughly $350 per ton for soybean HEFA.[13] To evaluate the impact on ARB's projections, we then input this value into CATS for soy renewable diesel, with a cost adjustment for waste oil conversion to account for lower yield. We re-ran the CATS model using these updated

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[12] 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.

[13] Pavlenko, Searle, and Christensen, "The Cost of Supporting Alternative Jet Fuels in the European Union."

assumptions and present our results for the baseline scenario and baseline scenario with one AAM event triggered in Figure 3 below. Here, the volumes of renewable diesel actual consumption (in black) are compared to scenarios modeled by ARB in solid colors, as well as. The two projections generated from the adjusted CATS model are illustrated in the dotted lines).

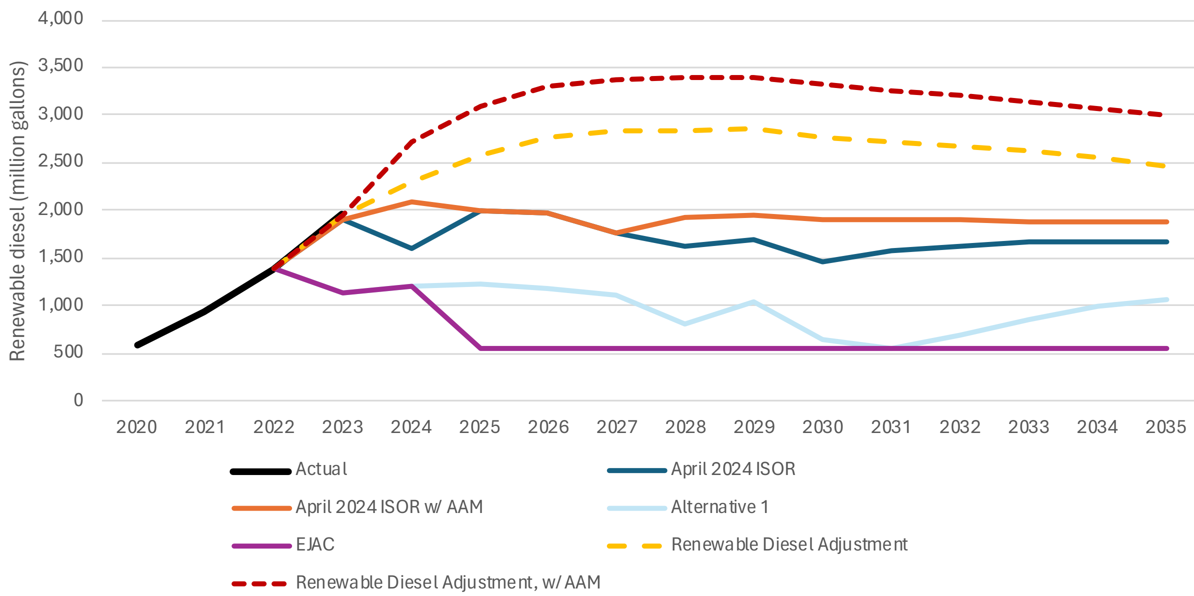

Figure 3: Renewable diesel volumes under proposed and ICCT-adjusted scenario runs

We find that renewable diesel consumption grows to 3.4 billion gallons under a scenario with the AAM triggered and 2.9 billion gallons without a change to the annual compliance trajectory. Comparatively, ARB's modeling falls short of the actual volumes of BBD that were reported in 2023 in quarterly summary reports. For example, while ARB predicts that BBD consumption (including biodiesel and SAF) will not exceed 2.3 billion gallons under the 45-Day Proposal and 2.4 billion gallons if the AAM is triggered, actual consumption of BBD was already 2.3 billion gallons in 2023.[14] While ARB concludes that current program design is sufficient to mitigate adverse environmental impacts from BBD consumption, we find that the emissions impacts of a rapidly growing BBD market are underestimated due to unrepresentative input assumptions.

Limiting California's reliance on lipids is critical to ensure that the LCFS avoids unintended, indirect emissions that could jeopardize its intended GHG targets. BBD consumption presents significant sustainability concerns because it can be sourced from feedstocks grown on high-carbon stock land.[15] BBD feedstocks grown on U.S. pasture and cropland

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[14] California Air Resources Board, "Low Carbon Fuel Standard Reporting Tool Quarterly Summaries."

[15] Hugo Valin et al., "The Land Use Change Impact of Biofuels Consumed in the EU: Quantification of Area and Greenhouse Gas Impacts," August 27, 2015.

also lead to greenhouse gas (GHG) emissions impacts from direct land-use change (LUC) and to a greater extent when growing feedstocks for biofuel displaces the same feedstocks consumed in competing sectors including food, animal feed, and consumer products.[16] Waste oils that are later converted to BBD do not directly contribute to LUC, but there is evidence of fraudulent reporting in the U.S. and elsewhere where virgin vegetable oil was miscredited as waste oil under regulatory fuel programs.[17]

Additional measures will be needed in the near-term to limit the supply of BBD entering the California market including imports from ecologically sensitive regions.[18] One such measure is to set a cap on the volume of lipid-based feedstocks credited under the LCFS; this proposal was explored in previous ICCT research[19] and has been implemented in similarly structured low-carbon fuel regulations in other countries, including Germany.[20] Though that analysis recommended a cap of approximately 1.2 billion gallons, lipid-based diesel consumption under the LCFS has already nearly doubled from 2021 levels. Therefore, a cap of approximately 2.3 billion gallons (similar to 2023 consumption levels) could maintain consistency between ARB's modeled scenarios without punishing existing producers.

This cap could be implemented in several ways:

A) By introducing a separate credit registry for lipid-based fuels and limiting the quantity of credits sold to meet annual LCFS compliance, based on the predetermined volume cap. Developing separate credit registries for different fuel types would be analogous to the trade of Renewable Identification Numbers (RINs) under the federal Renewable Fuel Standard (RFS) program.
B) By introducing a separate attribute, either energy or volume-based, as an allowance for the blending of lipids in California. Each obligated party would be limited according to the number of allowances they redeem, that represents to the maximum quantity of lipid-based fuel they can blend in a given year. These allowances could be allocated among obligated parties based on the volume of fuel

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16 US EPA, "Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis," February 2010.
17 European Anti-Fraud Office, "The OLAF Report 2019," n.d.; U.S. Attorney's Office Eastern District of Pennsylvania, "Owners Of Lehigh Valley Companies And Their Engineer Charged In Green Energy Fraud Scheme," December 21, 2015, https://www.justice.gov/usao-edpa/pr/owners-lehigh-valley-companies-and-their-engineer-charged-green-energy-fraud-scheme; Eli Moskowitz and Mira Sys, "How Biofuels Scams Have Undermined A Flagship EU Climate Policy," OCCRP, July 4, 2023, https://www.occrp.org/en/investigations/how-biofuels-scams-have-undermined-a-flagship-eu-climate-policy.
18 ARB, "LCFS Pathways Requiring Public Comments," accessed May 8, 2024, https://ww2.arb.ca.gov/resources/documents/lcfs-pathways-requiring-public-comments.
19 Jane O'Malley et al., "Setting a Lipids Fuel Cap under the California Low Carbon Fuel Standard" (Washington, D.C.: International Council on Clean Transportation, 2022), https://theicct.org/publication/lipids-cap-ca-lcfs-aug22/.
20 https://germanlawarchive.iuscomp.org/?p=315

sold in the California transportation market in by each obligated party in the previous year, or a set quantity of allowances equivalent to the cap could be awarded via auction.

Deliverability of biomethane-derived hydrogen

Data provided at the April workshop shows that ARB models a high reliance on dairy biomethane-derived hydrogen for its LCFS compliance. We find that by 2030, ARB's most ambitious scenario projects dairy biomethane-derived hydrogen will generate more credits than renewable diesel. The current book-and-claim system within the LCFS allows for indirect accounting of renewable natural gas (RNG) as long as it is injected into the North American natural gas grid. By virtue of the avoided methane emissions credit, this pairs high credit and compliance value with out-of-sector emissions reductions achieved at farms out of state. As a result, a hydrogen producer can purchase credits from an RNG producer, even when there is no direct, exclusive pipeline connection between the two facilities. The modeling does not distinguish between in state and out-of-state projects for dairy biomethane-derived hydrogen, thus making it difficult to determine to what extent future compliance will come from out-of-state projects.

Figure 4 provides an overview of existing dairy biomethane-derived hydrogen pathways certified under the LCFS by location, illustrating that 100% of these pathways in California are sourcing their biomethane from out-of-state digesters.[21] While the stated benefit of this system is to support hydrogen deployment, this accounting system favors existing fossil-based steam methane reforming (SMR) technologies by pairing them with a tradeable certificate for an out-of-state project. The high policy value for this pathway does not support the technology transition in California to more advanced technologies, such as hydrogen production via electrolysis, which would support emissions reductions in the long term. At present-day LCFS credit values, dairy biomethane-derived hydrogen would generate over $4 per kg, roughly 3 times the value of zero-CI electrolytic hydrogen produced from renewable electricity which would only generate approximately $1.50/kg.[22]

[21] California Air Resources Board, "Current Fuel Pathways," n.d., https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/current-pathways_all.xlsx.

[22] Assuming an LCFS credit value of $75/ton and an EER of 1.9 for the use of hydrogen in heavy-duty vehicle transport. Calculated via the LCFS credit price calculator. https://ww2.arb.ca.gov/sites/default/files/2022-03/creditvaluecalculator.xlsx

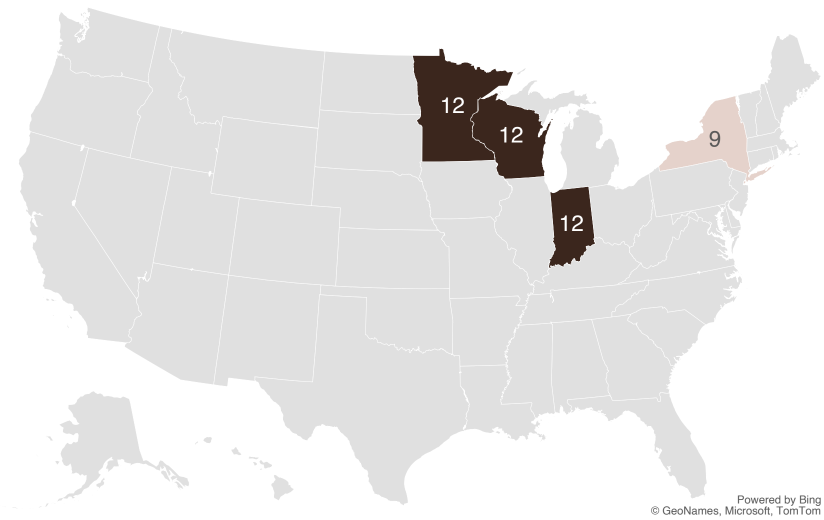

Figure 4: Geographic source of certified dairy RNG projects for hydrogen production in California.

Although deliverability requirements are proposed in the Initial Statement of Reasons (ISOR) released by ARB[23], they would only go into effect after January 1, 2046, for biomethane hydrogen projects that break ground after December 31, 2029. No deliverability requirements will be in effect for the projects that break ground before January 1, 2030.

To assess the potential risk to the LCFS, we draw upon data from the recently-published Census of Agriculture[24] to identify how many large-scale, centralized farms could be eligible to participate in the program. We chose 2,500 heads of cattle as a cut-off since this number represents profitable digester projects according to our previous assessment.[25] Figure 5 below illustrates the geographic distribution of these large farms across the country. Although California is home to around 31% of these farms nationwide, it is evident from the Census that there is a large pool of out-of-state farms (579 total) that could qualify for LCFS credits, though it is not possible to quantify their potential fuel production from the data. The Census data also indicates that California's overall number of dairy farms of this size increased 17% between 2017 and 2022. Although installing digesters is a viable

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[23] California Air Resources Board, "Staff Report: Initial Statement of Reasons," December 2023, https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf.

[24] 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/.

[25] 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/.

method for methane mitigation, it may not result in overall, absolute emissions reductions if the dairy industry keeps growing in California.

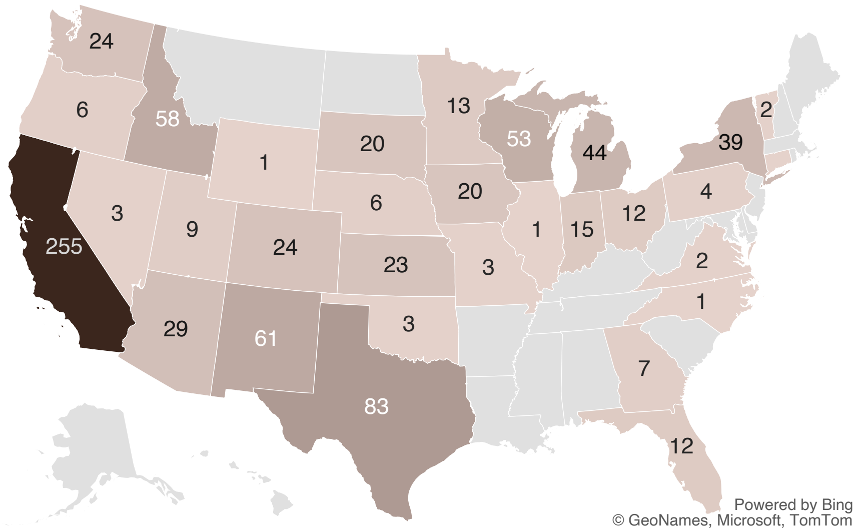

Figure 5: Distribution of dairy farms per state with dairy cattle head greater than 2,500.

Out-of-state swine farms capturing biogas could also take advantage of the generous LCFS credits. There are already several certified pathways for swine manure-derived RNG from Missouri being used as an offset for carbon intensity reductions for hydrogen production in California.[26] To show the risk from the swine farms, 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 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.

Allowing compliance from a broad, nationwide pool of farms also poses risks to the value of LCFS credit markets. Though the higher targets and AAM proposed in the ISOR are intended to lift LCFS credit prices, there is a risk that this goal may be diluted by out-of-sector avoided methane emissions supported by separate policies. For example, dairy digester-sourced RNG procured from outside of California benefits from D3 RINs, which trade at above $3 per ethanol-equivalent gallon and are insulated from recent price declines for other RIN categories.[27] This biomethane may also benefit from next year's 45Z Clean Fuel Production tax credit, which may award a further $1 per gallon-equivalent. While this is no different from the combination of incentives available for other transport fuels eligible for the LCFS, it does indicate that the viability of these projects—and

[26] California Air Resources Board, "Current Fuel Pathways."

[27] https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information

therefore, the attributability of avoided methane credits to the LCFS—is not solely attributable to the program and therefore an additional guardrail may be necessary.

In summary, the high compliance value of manure biomethane-derived hydrogen is inconsistent with its contribution to in-state methane reduction goals or transport sector decarbonization. The loose deliverability requirements will do more to facilitate the deployment of digesters in other states, rather than investment in hydrogen conversion technologies in California. The risk of moving forward with loose deliverability requirements is acute; there are hundreds of out-of-state dairy and thousands of swine farms that could take advantage of these incentives.

To mitigate these risks, we recommend that ARB establish a geographic deliverability requirement that connects dairy RNG directly to hydrogen producers in California as soon as possible. Therefore, we recommend that ARB align the deliverability requirements for biomethane used as a hydrogen feedstock with geographic deliverability requirements similar to those required for low-CI electricity to ensure better geographic correlation and focus support on pathways which tangibly reduce emissions in California. A simple geographic deliverability requirement will be more transparent, easier to implement, and is precedented from the deliverability requirements for low-CI electricity. Drawing from an analysis conducted by the U.S. Department of Energy (DOE) for 45V tax credit implementation, we recommend that ARB limit geographic eligibility for biomethane to the states of Washington, Oregon, and California, as this would be roughly consistent with the geographic deliverability for electricity proposed for 45V.[56] Alternatively, ARB can reference geographic zones from the U.S. natural gas transmission network to set its deliverability boundaries.[57]