DOCKETED	
Docket Number:	25-IEPR-04
Project Title:	Hydrogen
TN #:	265703
Document Title:	Earthjustice Comments on IEPR Commissioner Workshop on Firm Zero-Carbon Resources and Hydrogen
Description:	N/A
Filer:	System
Organization:	Sara Gersen
Submitter Role:	Public
Submission Date:	8/19/2025 1:53:05 PM
Docketed Date:	8/19/2025

Comment Received From: Sara Gersen
Submitted On: 8/19/2025
Docket Number: 25-IEPR-04

Earthjustice Comments on IEPR Commissioner Workshop on Firm Zero-Carbon Resources and Hydrogen

Additional submitted attachment is included below.

August 19, 2025
Submitted Electronically

Re: Earthjustice Comments on Integrated Energy Policy Report Commissioner Workshop on Firm Zero-Carbon Resources and Hydrogen

Dear Ms. Nakagawa,

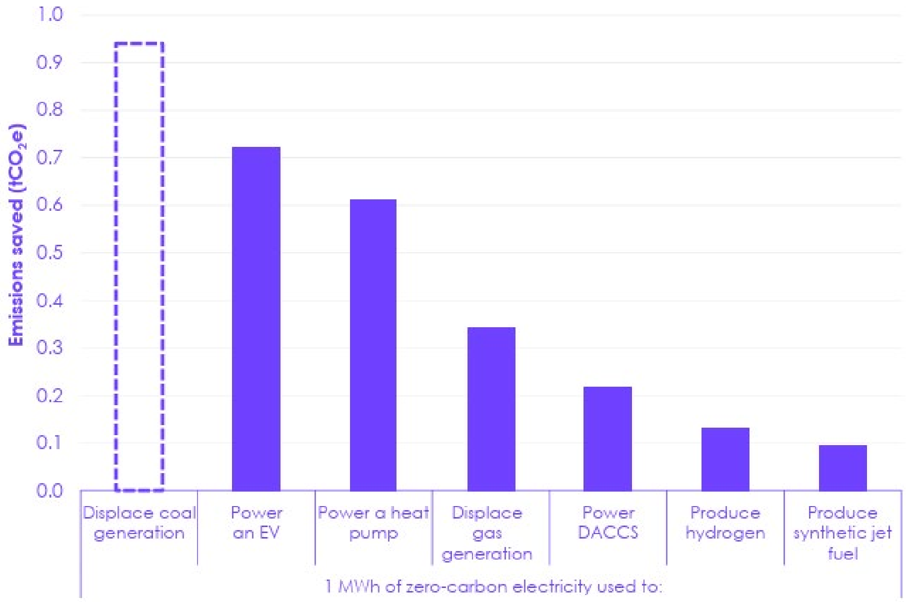
Earthjustice appreciates the opportunity to comment on the July 29, 2025, Integrated Energy Policy Report ("IEPR") workshop. In these comments, we recommend policy strategies for advancing clean energy deployment that the IEPR should consider. We provide feedback on the scenarios that California Energy Commission ("CEC") staff are modeling pursuant to Senate Bill ("SB") 1075. And we discuss the value proposition of using biogenic materials such as agricultural and forest biomass resources as a fuel.

Earthjustice is concerned that the proposed SB 1075 analysis dramatically overestimates hydrogen demand in all scenarios. The CEC should study scenarios with lower levels of hydrogen demand that plausibly reflect the amounts of hydrogen the transportation and electric sectors would use in a least-cost decarbonization pathway. Without such realistic scenarios, the IEPR will not properly serve the public and decisionmakers who rely on it. One major theme that emerged from the CEC staff presentations on hydrogen is that it would take a tremendous amount of resources to produce and store to meet the level of demand in each of the scenarios considered. Given the enormous resource demands of hydrogen production, California policymakers would likely take great comfort to understand that the state can meet its ambitious climate goals through scenarios that are less reliant on hydrogen—and that these scenarios would likely reduce the cost of decarbonization.

The IEPR should frankly acknowledge that overestimating hydrogen demand and producing an oversupply of hydrogen could inadvertently undermine the energy transition. A primary risk of over-reliance on hydrogen is that it could divert scarce or low-cost renewable generation that could more efficiently decarbonize other sectors. As illustrated by the following figure from the U.K. Climate Change Committee ("UKCCC"), renewable generation resources can drive more emissions reductions when they power electric vehicles or displace fossil fuels on the electric grid than when they produce hydrogen:[1]

[1] U.K. Climate Change Committee, The Seventh Carbon Budget (Feb. 2025) ("UKCCC Seventh Carbon Budget"), at 367, https://www.theccc.org.uk/wp-content/uploads/2025/02/The-Seventh-Carbon-Budget.pdf.

Figure 10.8 Best uses for zero-carbon electricity



Description: Chart shows emission savings from using 1 MWh of zero-carbon electricity, with the highest savings coming from direct electrification uses (for example, in electric vehicles and heat pumps) and the lowest savings for indirect uses (such as converting to hydrogen).
Source: CCC analysis.
Notes: (1) Coal is shown as a dashed outline because it has now been phased out of the UK electricity system. (2) 'EVs' are electric vehicles; 'DACCS' is direct air carbon capture and storage.

Deploying the necessary renewables to decarbonize the grid and growing electric demand from vehicles and the building sector is already a challenge,[2] and policymakers should be careful not to exacerbate that challenge by funneling these resources into uneconomic hydrogen production.

I. Policy Levers for Advancing Clean Energy Deployment

The IEPR is an opportunity for the CEC to identify policy strategies for advancing California's ambitious climate goals and addressing its air quality crisis. Earthjustice recommends considering the following policies:

A) mandating the use of green hydrogen in sectors that already rely on hydrogen;
B) zero-emissions mandates for equipment that could operate on hydrogen or hydrogen derivatives;
C) tracking hydrogen emissions in the State greenhouse gas inventory; and

[2] Nationally, just deploying enough clean energy to eliminate emissions from the electricity sector by 2035 will be a titanic effort, requiring a six-fold increase over historic rates of renewable energy deployment, even if demand for electricity were static. Leah C. Stokes, *Cleaning Up the Electricity System*, Democracy Journal https://democracyjournal.org/magazine/56/cleaning-up-the-electricity-system/.

D) affirming that California policy does not support internal combustion engine ("ICE") hydrogen vehicles.

A. <u>The IEPR should analyze green hydrogen mandates for sectors that already rely on hydrogen.</u>

At the July 29 IEPR workshop, the Bloomberg New Energy Finance presentation noted multiple trends that are likely to worry policymakers seeking to establish a market for renewable hydrogen. A small fraction of announced green hydrogen production capacity has contracted offtake.[3] A large majority (78,000 out of 108,000 tons) of the contracted demand for so-called clean hydrogen in California is for hydrogen produced from fossil fuels with carbon capture, which is known as "blue" hydrogen.[4] One of the significant advantages that fossil hydrogen has over green hydrogen is that it faces less policy uncertainty.[5] California's focus on using clean hydrogen in the power and transportation sector is the opposite of what is happening in the rest of the world, where demand for clean hydrogen is coming from sectors with commercially ready and established uses.[6] Elsewhere in the world, sector-specific mandates are a driver of clean hydrogen demand.[7]

To address this confluence of challenges, the IEPR should discuss potentially adopting state-level mandates for using green hydrogen in products or industrial processes that have commercially ready and established uses for hydrogen, such as fertilizer. Requiring industries that currently use hydrogen to ramp up the amount of their hydrogen demand that is provided by green hydrogen can catalyze effective market creating for green hydrogen because these industries do not have an alternative to using hydrogen.[8] In contrast, new hydrogen producers like Redding Rancheria are currently targeting hydrogen demand in sectors where it is far less certain; Mr. Hayward observed the challenge of building a business around supplying hydrogen fueling stations in the transportation sector while the number of those fueling stations is going down.[9]

A mandate to decarbonize with green hydrogen can also ensure that "blue" fossil hydrogen does not undermine the market for green hydrogen that is produced in a manner that aligns with California's public health and deep decarbonization goals: hydrogen produced

---

[3] Payal Kaur, Bloomberg New Energy Finance, presentation at IEPR Commissioner Workshop on Firm Zero-Carbon Resources and Hydrogen, https://energy.zoom.us/rec/play/Q0vYq6e17T6-c76kdVlJRk0CtWjaXiGdodJr0b_FvLEsNOjxaAi9jsHSzVPzgy5JcEM5TwDNrk5UVDVu.inphr0ywUpfoYGUY (at around 3:09, providing global data).
[4] *Id.* at around 3:11. This is especially striking, considering that 89% of announced capacity in California is for green hydrogen and the remaining 11% is for blue. *Id.* at around 3:07.
[5] *Id.* at around 3:11.
[6] *Id.* at around 3:11:40.
[7] *Id.* at around 3:12:25 (discussing mandates for decarbonized steel).
[8] Michael Liebriech's hydrogen ladder indicates that fertilizer and desulpherization (which are also currently the two biggest sources of demand for hydrogen) are applications with "no real alternative" to hydrogen. Michael Liebreich, Hydrogen Ladder Version 5.0 (Oct. 20, 2023), https://mliebreich.substack.com/p/hydrogen-ladder-version-50.
[9] Jeremy Hayward, Redding Rancheria, IEPR workshop recording at around 3:27.

through the zero-emissions process of powering electrolysis with new solar and wind resources. The IEPR should at least begin the conversation about mandates for hydrogen-dependent industries to transition to green hydrogen because there are currently no targeted California policies to decarbonize these industries. This is a critical policy gap, as producing hydrogen from fossil fuels to meet current demand is a substantial source of climate pollution.[10]

B. The IEPR should analyze zero-emissions mandates for vehicle segments and stationary sources equipment that could run on hydrogen or hydrogen derivatives

California's most effective policies for decarbonizing specific end-use equipment have historically been zero-emissions mandates. The State's zero-emissions vehicle ("ZEV") mandates have been transforming the market for on-road vehicles for more than a decade. The California Air Resources Board ("CARB") first introduced ZEV regulations for light-duty vehicles, adopting its first Advanced Clean Cars rule in 2012 and Advanced Clean Cars in 2022. Advancing technologies supported ZEV regulations for heavier vehicles, such as the Innovative Clean Transit rule adopted in 2018 and the Advanced Clean Fleets rule adopted in 2023. Likewise, CARB began transitioning offroad equipment to zero-emission technology with its 2021 Small Off Road Engines rule and 2024 forklifts rule.[11] While it is unclear how large a role hydrogen will play in compliance with these rules, the rules transitioning the transportation sector to zero-emissions technologies are a necessary (if not sufficient) condition for creating demand for hydrogen in that sector. Accordingly, the IEPR should acknowledge the importance of adopting ZEV regulations to cover additional vehicle segments, including regulations to transition locomotives to zero-emissions technologies.[12]

Zero-emissions regulations will likely prove equally central to addressing pollution from stationary sources. Meeting health-based air quality standards will require a widespread transition to zero-emission equipment for both stationary and mobile sources in California's most polluted air basins.[13] Accordingly, the South Coast Air Quality Management District has adopted a zero-emissions rule for some industrial boilers and process heaters.[14] The IEPR should discuss the potential for zero-NOx stationary source standards to catalyze demand for equipment that uses hydrogen, hydrogen derivatives, and/or electricity for end uses that currently rely on combustion. The July 29 workshop presentation of Craig Klassmeyer from Kaizen Clean Energy

[10] Today, producing hydrogen from fossil fuels is responsible for about 2.5% of global emissions. Liebriech, *supra*.
[11] CARB, Small Off Road Engines (SORE), https://ww2.arb.ca.gov/our-work/programs/small-off-road-engines-sore; CARB, Zero-Emission Forklifts, https://ww2.arb.ca.gov/our-work/programs/zero-emission-forklifts.
[12] CARB adopted a regulation that would have increased the use of locomotive zero-emissions technology in 2023, but repealed the regulation in 2025 because the U.S. EPA failed to issue a waiver to allow California to enforce this rule. CARB, Reducing Rail Emissions in California, https://ww2.arb.ca.gov/our-work/programs/reducing-rail-emissions-california/about.
[13] South Coast Air Quality Management District, 2022 Air Quality Management Plan, at ES-5 (Dec. 2022), http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2022-air-quality-management-plan/final-2022-aqmp/final-2022-aqmp.pdf?sfvrsn=16.
[14] South Coast Air Quality Management District, South Coast AQMD Approves Rule to Accelerate the Transition to Zero-Emission for Building Water Heaters (June 7, 2024), https://www.aqmd.gov/docs/default-source/news-archive/2024/1146-2-June-7-2024.pdf.

provides one example of a category of stationary source equipment that appears appropriate for zero-NOx regulations: mobile electricity generation equipment. The presentation explains that zero-NOx equipment has a lower levelized cost of energy than diesel and propane gensets,[15] showing that the market for mobile generators is ripe for transformative regulation.

C. The CEC should recognize the importance of including hydrogen emissions in California's greenhouse gas inventory.

California's statewide greenhouse gas inventory "is an important tool for establishing historical emission trends and tracking California's progress in reducing GHGs."[16] The inventory will not adequately serve these purposes if it ignores emissions of hydrogen, particularly if these emissions increase as hydrogen expands its role in the California economy. Hydrogen is an indirect greenhouse gas. A recent study calculated the 100-year global warming potential ("GWP") for hydrogen at 12.8 ± 5.2 and the 20-year GWP at 40.1 ± 24.1.[17] As the universe's smallest molecule, hydrogen is likely to leak and enter the atmosphere at each stage of the supply chain.[18] In addition to entering the atmosphere through inadvertent leaks, industry also vents hydrogen in routine processes, such as venting gaseous hydrogen from liquid hydrogen storage tanks to relieve pressure and reduce hazards.[19] At the July 29 IEPR workshop, the representative from Linde stated that boil off "should be less than 7%, less than 10% for sure." It is essential for California to track these emissions and account for them in its greenhouse gas inventory. Otherwise, the State could fail to achieve its climate goals (or achieve them only on paper, as it ignores significant real-world hydrogen emissions). Therefore, California should include hydrogen leaks in its statewide greenhouse gas inventory.

D. The CEC should help create market certainty for zero-emissions hydrogen vehicles by clearly stating that polluting internal combustion engines have no role in the future of California's on-road transportation.

Industry lobbyists are pushing aggressively for investments in and accommodations for ICE hydrogen vehicles, even though deployment of these polluting vehicles is inconsistent with the ZEV policies that California is implementing to attain health-based air quality standards. For instance, a hydrogen trade association has lobbied the CEC to support a truck fueling corridor

[15] Craig Klassmeyer, Kaizen Clean Energy, IEPR Workshop recording at around 4:14.
[16] CARB, Current California GHG Emission Inventory Data, https://ww2.arb.ca.gov/ghg-inventory-data.
[17] Didier Hauglustaine et al., Climate benefit of a future hydrogen economy, 3 Commc'ns Earth & Env't 295 (2022), https://doi.org/10.1038/s43247-022-00626-z.
[18] Abdurahman Alsulaiman, The Oxford Inst. for Energy Stud., Review of Hydrogen Leakage along the Supply Chain: Environmental Impact, Mitigation, and Recommendations for Sustainable Deployment, at 13, Figure 6 (Nov. 2024), https://www.oxfordenergy.org/wpcms/wp-content/uploads/2024/11/ET41-Review-of-Hydrogen-Leakage-along-the-Supply-Chain.pdf.
[19] *Id.* at 16.

that supplies both fuel cell and ICE trucks[20] and lobbied CARB to promote ICE vehicles.[21] However, hydrogen ICE vehicles represent a significant threat to public health, as researchers have found that "H2ICE has comparable NOx output as diesel for higher loads."[22] In general, ICE vehicles are incompatible with California's ZEV mandates because all ICE vehicles emit NOx.

In the IEPR, the CEC should recognize that ICE vehicles have no role in the future of California's on-road transportation and, consequently, state policy does not support investments in fueling or manufacturing these vehicles. Clear policy direction for focusing on ZEVs is important for avoiding stranded assets. The fuel cell vehicles that are capable of meeting California emission mandates have distinct fueling needs and, consequently, investments in ICE fueling are likely to lead to stranded assets. For example, fuel cell vehicles require hydrogen at a lower pressure[23] and require hydrogen with higher levels of purity[24] than ICE vehicles. A clear statement in the IEPR about California's commitment to only subsidizing infrastructure that is compatible with ZEV goals would help provide market certainty for zero-emissions technologies.

II. The SB 1075 Analysis Overestimates Hydrogen Demand and Must Be Revised to Include a Realistic Low Hydrogen Scenario and Revised to Include Hydrogen Production Scenarios that Align with California's Climate and Public Health Policies.

The CEC staff analysis presented at the July 29 workshop raises alarms about the onerous costs and fossil fuel dependency involved with pursuing the preliminary demand and production scenarios. Despite labeling some of the demand scenarios as "low," all the scenarios discussed at the workshop include far greater hydrogen use than policymakers should expect in a least-cost decarbonization pathway. In the final IEPR, it is essential to give policymakers information about plausible scenarios in which California avoids the costs of over-reliance on hydrogen. Without a truly "low" hydrogen scenario, policymakers will not be able to make informed decisions about how to best decarbonize the state's economy.

---

[20] California Hydrogen Business Council, Response to 24-EVI-01, Joint Workshop on Concepts for the CFI West Coast Truck Charging and Fueling Corridor Project – California Hydrogen Business Council Comment (Feb. 28, 2025) at 2, https://californiahydrogen.org/wp-content/uploads/2025/03/CEC-24-EVI-01-Feb-28-2025-CHBC-comments.pdf.

[21] California Hydrogen Business Council, Comments on Gov. Newsom Executive Order N-27-25 (Aug. 1, 2025), https://californiahydrogen.org/wp-content/uploads/2025/08/CHBC-Comments-on-CARB-ZEV-Forward-August-1-2025-Final.pdf.

[22] U.S. Department of Energy, Overview of Hydrogen Internal Combustion Engine (H2ICE) Technologies, PDF p. 97, https://www.energy.gov/sites/default/files/2023-03/h2iqhour-02222023.pdf.

[23] Cummins, How does the fuel delivery system work for hydrogen ICE, hydrogen fuel cell, and natural gas vehicles? (Jan. 11, 2024), https://www.cummins.com/news/2024/01/11/how-does-fuel-delivery-system-work-hydrogen-ice-hydrogen-fuel-cell-and-natural-gas.

[24] U.S. Department of Energy, Overview of Hydrogen Internal Combustion Engine (H2ICE) Technologies, *supra*, presentation of Sandia National Laboratory Principal Investigator Ales Srna at slide 6.

A. Hydrogen potential in the transportation sector is far lower than the level presented in the CEC's analysis.

The 2025 IEPR is an important opportunity to provide an updated assessment of the potential role of hydrogen in the transportation sector that takes advantage of the latest data, which generally indicates a smaller economic role for hydrogen than analysts had predicted just a few years ago. For example, independent analysts at DNV estimated in 2024 that hydrogen would provide just 1% of on-road energy demand by 2050—a dramatic downward revision of its projection in 2023 that hydrogen would provide about 3% of on-road energy by midcentury.[25] The UKCCC also commissioned an economic analysis of competing options for decarbonizing vehicles and concluded that "there will be no hydrogen cars or vans, and very little or potentially even no role for hydrogen in heavier vehicles."[26] The CEC should take care to avoid the mistakes of past modeling efforts, which have often overestimated the potential market for fuel cell vehicles[27] and underestimated the potential for battery electric vehicles.[28] The proposed scenarios do not reflect these learnings. In fact, the proposed approach moves in the opposite direction of these real-world developments by modeling scenarios with even more demand for hydrogen in the transportation sector than what the CEC included in the 2023 IEPR.[29]

The CEC's analysis of the potential for hydrogen in the transportation sector will only be useful to policymakers and the public if it reflects viable or likely pathways for achieving State goals. Models that assume hydrogen use at uneconomic levels do not serve this purpose because

---

[25] Leigh Collins, DNV slashes forecast for hydrogen use in road transport amid advances in battery-electric trucks, Hydrogen Insight (Oct. 17, 2024), https://www.hydrogeninsight.com/transport/dnv-slashes-forecast-for-hydrogen-use-in-road-transport-amid-advances-in-battery-electric-trucks/2-1-1725398.

[26] UKCCC Seventh Carbon Budget at 146, https://www.theccc.org.uk/wp-content/uploads/2025/02/The-Seventh-Carbon-Budget.pdf. The supporting documents for this report include ERM, ZEV HDV Uptake Trajectories: Modeling Assumptions (2024), https://www.theccc.org.uk/wp-content/uploads/2025/02/ZEV-HDV-uptake-trajectories-ERM.pdf.

[27] For instance, when CARB adopted the first Advanced Clean Cars rule in 2012, it estimated cumulative sales of light-duty FCEVs to reach 56,844 by 2022. In the 2017 midterm review for the rule, CARB estimated that cumulative sales of light-duty FCEVs would reach 35,083 by 2022. CARB, 2017 ZEV Calculator Tool *available at* https://ww2.arb.ca.gov/resources/documents/2017-midterm-review-report. However, just 11,897 light-duty FCEVs were on the road in California at the end of 2022. CEC, Light-Duty Vehicle Population in California, https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics/light-duty-vehicle. In its 2022 Advanced Clean Cars II rulemaking, CARB found that California could achieve 100% sales of zero-emission light-duty vehicles with just 2.8% sales of FCEVs. CARB, Final Statement of Reasons for Rulemaking for the Advanced Clean Cars II Regulations, Appendix F at 7 (August 2022).

[28] In 2019, the International Energy Agency's annual Electric Vehicle Outlook estimated EVs would make up 9% of global car sales by 2025. By 2022, they revised that estimate to 15% by 2025. In April 2023, they announced that EV sales shares are set to reach 18% this year. Hannah Ritche, "Electric Cars are the New Solar: People Will Underestimate How Quickly They Will Take Off" (May 7, 2023) https://www.sustainabilitybynumbers.com/p/ev-iea-projections; IEA, "Demand for electric cars is booming, with sales expected to leap 35% this year after a record-breaking 2022" (Apr. 26, 2023) https://www.iea.org/news/demand-for-electric-cars-is-booming-with-sales-expected-to-leap-35-this-year-after-a-record-breaking-2022.

[29] Compare the transportation-sector hydrogen demand in the 2023 IEPR scenarios (provided on slide 5 of the first CEC staff presentation) with the proposed scenarios for the 2025 IEPR (provided on slide 7 of the same presentation).

it is highly improbable that fleets will choose unnecessarily expensive compliance pathways for California's ZEV rules. If the IEPR includes the proposed scenarios, it is important to prominently disclose that they are not supported economic modeling so that readers can weigh them properly. It is also important for the IEPR to include more realistic scenarios.

1. *Any reasonable estimate for the potential demand for hydrogen in the transportation sector must account for hydrogen's unfavorable economics as a transportation decarbonization tool.*

An analysis of the economic potential for hydrogen in the transportation sector should account for at least three major cost categories in the total cost of ownership of hydrogen vehicles: (1) fueling (including fuel, delivery, and dispensing); (2) vehicle; and (3) maintenance costs. This analysis must also include reasonable assumptions for each of these cost categories for both hydrogen vehicles and battery-electric vehicles, which are the primary alternative technology for complying with California's zero-emission vehicle policies.

Fueling: To avoid relying on overly optimistic assumptions about fueling costs, **the IEPR should analyze a scenario in which the delivered cost per kilogram of hydrogen falls within the range of what has been achieved historically**. We appreciate CEC's analysis of multiple price points for delivered hydrogen in the 2023 IEPR. However, we are concerned that the $8/kg and $5/kg scenarios are both unsupported by data on cost trends. Not only are the current costs of hydrogen fueling far above $8/kg,[30] but hydrogen producers will need to incur additional costs to transition from the current practice of producing hydrogen from fossil fuels to align with California's climate and air quality goals.

A significant portion of the cost of hydrogen fueling is the cost of delivery and the dispensing equipment, which will likely put delivered costs of $8/kg out of reach. A 2020 U.S. Department of Energy analysis that used California data found that delivery and dispensing costs alone ranged from $8.17–9.46/kg for gaseous hydrogen and $8.31–11.35/kg for liquid hydrogen.[31] The pricing for delivery of liquid hydrogen by tube trailer will likely be relevant for the majority of potential hydrogen users in the transportation sector, as California's hydrogen hub envisions this strategy for fueling buses and delivery trucks.[32] Liquifying hydrogen is a costly and energy-intensive process because hydrogen only becomes liquid at extremely cold temperatures (-235 °C); using current technology, liquifying hydrogen consumes more than 30% of its energy content.[33] Further, while the CEC might expect to see some decline in the cost of

[30] While the 2023 IEPR indicated that some transit agencies have paid delivered costs of less than $9 per kilogram of hydrogen, it is not clear whether this figure includes the significant costs of constructing and maintaining fuel dispensing infrastructure.
[31] U.S. Department of Energy, *Hydrogen Delivery and Dispensing Cost*, at 2 (Aug. 25, 2022) https://www.hydrogen.energy.gov/pdfs/20007-hydrogen-delivery-dispensing-cost.pdf.
[32] ARCHES Technical Submission to DOE – April 2023, at 13, Figure 3.1, https://archesh2.org/wp-content/uploads/2024/08/ARCHES-Technical-Volume-Redacted.pdf.
[33] U.S. Department of Energy, *Liquid Hydrogen Delivery,* https://www.energy.gov/eere/fuelcells/liquid-hydrogen-delivery (captured Mar. 27, 2023).

hydrogen refueling infrastructure as the industry gains additional experience, these kinds of infrastructure projects do not typically yield dramatic cost reductions with economies of scale.

Vehicle: To model the economic potential of hydrogen in the transportation sector, vehicle costs are the second cost category where the CEC will need reliable inputs and assumptions. A recent study by the International Council on Clean Transportation ("ICCT") surveyed a body of literature on vehicle price projections and found that battery electric vehicles would maintain a price advantage over hydrogen vehicles for short-haul and rigid class 8 trucks.[34] The study also found that battery electric vehicles will beat diesel trucks on price in these categories by 2040, but hydrogen vehicles would not. The sole vehicle category where hydrogen alternatives beat battery electric vehicles on price by 2040 was long-haul class 8 tractor trucks, and even in that category fuel cell vehicles achieved only a slightly advantageous retail price.[35] David Cebon, the Director of Cambridge's Centre for Sustainable Road Freight, has explained why fuel cell vehicles are more costly to manufacture today than a comparable battery electric vehicle: a fuel cell vehicle has all the components in a battery electric vehicle (with a smaller battery) plus complicated fuel cell, hydrogen tank, and hydrogen delivery equipment.[36] Professor Cebon predicts that the cost advantage of battery electric vehicles will widen as the massive ramp-up of battery manufacturing for the light-duty sector drives learning curves that bring down costs for all battery electric vehicles.[37] **To reduce the risk of underestimating the costs of hydrogen vehicles, at a minimum, the CEC should expect the cost curves for fuel cell and battery electric vehicles to mirror the trends in the literature that ICCT surveyed.**

Maintenance: Maintenance costs are the final cost category that the CEC should include in any analysis of the economics hydrogen in the transportation sector. While California transit agencies have demonstrated the ability to reduce maintenance costs by transitioning from combustion engines to battery electric buses, a transition to fuel cell electric buses has generally increased maintenance costs.[38] Just as the complexity of fuel cell vehicles makes them more expensive to manufacture than battery electric vehicles, the additional components also make fuel cell vehicles more expensive to maintain.[39] The unique maintenance challenges associated with hydrogen vehicles could dissuade fleet operators from buying a few hydrogen vehicles for

[34] Yihao Xie et al, ICCT, Purchase costs of zero-emission trucks in the United States to meet future Phase 3 GHG standards (March 2023) at 16–20, https://theicct.org/wp-content/uploads/2023/03/cost-zero-emission-trucks-us-phase-3-mar23.pdf.
[35] *Id.* at 22 (Fig. 17).
[36] Einride, "The gap will widen", says prof. David Cebon on electric vs hydrogen (March 5, 2023), https://www.einride.tech/insights/prof-david-cebon-on-electric-vs-hydrogen-the-gap-will-widen.
[37] *Id.*
[38] California Air Resources Board, Literature Review on Transit Bus Maintenance Cost (2020) (summarizing Foothill Transit's maintenance cost savings on page 9, AC Transit's maintenance costs for diesel and fuel cell buses on page 16, and the increased maintenance costs SunLine transit incurred for fuel cell buses relative to CNG buses on page 19), https://ww2.arb.ca.gov/sites/default/files/2020-06/Appendix%20G%20Literature%20Review%20on%20Transit%20Bus%20Maintenance%20Cost.pdf.
[39] Michael Barnard, Hydrogen Fleets are Much More Expensive to Maintain Than Battery & Even Diesel, CleanTechnica (Jan. 27, 2024), https://cleantechnica.com/2024/01/26/hydrogen-fleets-are-much-more-expensive-to-maintain-than-battery-even-diesel/.

edge cases that might be challenging for current battery electric technology.[40] **Any analysis of the potential ZEV market share for hydrogen fuel cell vehicles must account for them having higher maintenance costs than their battery electric competitors.**

Many independent experts have found that battery electric vehicles will be the dominant zero-emission technology in the medium- and heavy-duty sector because of their favorable total cost of ownership ("TCO"), which accounts for fuel, vehicle and maintenance costs and is the main driver of fleet purchase decisions. Academics,[41] truck manufacturers,[42] and multiple independent analysts have concluded that battery electric technology is best positioned to decarbonize the vast majority of road-transport—even long-haul trucking.[43] Unrealistically low estimates for the TCO of hydrogen vehicles could stall the transition to zero-emission vehicles, if fleet owners wait in vain for steep price declines in hydrogen options instead of buying lower-cost battery electric vehicles.

For locomotives, any analysis of the potential for hydrogen would be incomplete without considering the opportunities for decarbonization with catenary electrification. As the federal Action Plan for Rail Energy and Emissions Innovation explains, "[c]atenary is a **globally adopted, off-the-shelf, safe, efficient, reliable** zero-emission technology for line-haul, industrial, intercity passenger, and commuter rail applications."[44] The Action Plan identifies a tremendous cost-savings opportunity from transitioning to catenary: "The most recent nationwide cost-benefit analysis of freight rail electrification was published in 1983, which found that **electrifying a core 29,000-mile subset of the freight rail network would save $5.2 billion per year**, adjusted for 2024 U.S. dollars (USD)."[45] It is essential to consider both full and discontinuous catenary (catenary + battery), as recent studies have found that intermittent catenary is the most cost-effective approach to decarbonizing the non-electrified portions of rail

---

[40] For instance, in its recent general rate case before the California Public Utilities Commission, SoCalGas requested $816,000 for a labor training program to address the complexities of hydrogen vehicle maintenance, including (1) The hydrogen gas cylinders have a much larger pressure rating and are significantly heavier than gas powered vehicles, which require special lifting devices to remove and install; (2) Hydrogen gas is colorless and odorless. The vehicles are equipped with several sensors that detect hydrogen gas. These require testing and calibration at regular intervals, which also require special tools; (3) To "open" the hydrogen system for service, the garage needs to be equipped with hydrogen detection sensors, a hydrogen evacuation system, and a system to drain the hydrogen gas out of the cylinders before opening; (4) The hydrogen fuel cell produces high voltage (300+ volts) to power an electric motor and a high-voltage battery pack. Handling the high voltage components requires additional special tools, and Personal Protective Equipment to help prevent injury or death. Response to Data Request CEJA-SEU-008, Q.7. The Commission denied recovery of these costs. CPUC Decision 24-12-074 at 578.

[41] Patrick Plötz, *Hydrogen technology is unlikely to play a major role in sustainable road transport*, 5 Nature Elecs. 8 (Jan. 2022), https://www.nature.com/articles/s41928-021-00706-6.

[42] Matthias Grundler and Andreas Kammel, *Why the future of trucks is electric*, TRATON (Apr. 13, 2021), https://traton.com/en/newsroom/current-topics/furture-transport-electric-truck.html.

[43] Amol Phadke et al., *Why Regional and Long-Haul Trucks are Primed for Electrification Now*, Berkeley Lab (Mar. 2021), https://etapublications.lbl.gov/sites/default/files/updated_5_final_ehdv_report_033121.pdf; Transport & Environment, *Why the future of long-haul trucking is electric* (June 18, 2021), https://www.transportenvironment.org/discover/why-the-future-of-long-haul-trucking-is-electric/.

[44] U.S. Department of Energy, Department of Transportation, Environmental Protection Agency, Department of Housing and Urban Development (Dec. 2024) at 32 (emphasis in original).

[45] *Id.* (emphasis in original).

networks in Norway and the United Kingdom and the German national rail company is already constructing an intermittent catenary system.[46] In Germany, a hydrogen rail system would have been three times more expensive than discontinuous catenary.[47] Rail operators in Germany and Austria have abandoned experiments with hydrogen technology because electric alternatives could decarbonize their equipment at lower cost.[48] After careful analysis, the CEC may determine that there is zero economic potential for hydrogen locomotives in California.

2. *Both the proposed scenarios overestimate the potential demand for hydrogen in the transportation sector.*

The proposed scenarios do not provide credible estimates of potential hydrogen demand because they are not based on analysis of least-cost compliance pathways for ZEV regulations or climate policies. For instance, for freight trucks, the proposed "policy scenario" relies on CARB's Advanced Clean Fleets ("ACF") rulemaking. In adopting the ACF, CARB hard-coded assumptions into its 2022 cost-effectiveness models for the fraction of ZEVs in different vehicle classes that would be hydrogen fuel cell, as opposed to battery electric. CARB did not analyze whether it would be economic to use hydrogen at the assumed levels instead of deploying more battery-electric vehicles. Given the more recent research discussed above, some of CARB's assumptions appear highly unlikely, such as the assumptions that 25% of ZEV day cab tractors would operate on hydrogen beginning in 2027 or that 50% of sleeper cab tractors would operate on hydrogen beginning in 2027. Consequently, the proposed policy scenario likely overestimates the role of hydrogen in the transportation sector and it would be misleading to portray this scenario as representing "low" hydrogen demand. The proposed "high" scenario pushes hydrogen demand in the transportation sector even further, creating the false impression that the policy scenario is a moderate forecast.

For the public and policymakers to properly weigh these scenarios, the IEPR should identify the projected demand (in MT) of hydrogen from each vehicle segment and identify what percentage of the vehicle fleet or new vehicle sales relies on hydrogen in each scenario. The IEPR should also explicitly disclose that the proposed scenarios are not based on economic modeling that accounts for the comparative costs of purchasing, fueling, and maintaining hydrogen and battery-electric vehicles.

3. *The CEC can and must develop a plausible "low" scenario for the IEPR analysis to be useful to policymakers.*

The CEC should study a scenario with "low" hydrogen use in the transportation sector that is validated by independent analysis of where hydrogen is likely to emerge as an economically competitive decarbonization strategy. For instance, the CEC could develop a plausible lower-use scenario by modeling a scenario in which the only transportation

[46] *Id.* at 30.
[47] *Id.* at 45.
[48] *Id.*

applications that use hydrogen are those that that rank a "B" or above in Michael Liebriech's hydrogen ladder: shipping and jet aviation.[49] Excluding hydrogen use in on-road vehicles would also be consistent with the recent findings of the UKCCC that "there will be no hydrogen cars or vans, and very little or potentially even no role for hydrogen in heavier vehicles."[50] It is important for policymakers to understand the full range of the transportation sector's potential reliance on hydrogen, which requires modeling scenarios that are less exuberantly optimistic about the role of hydrogen.

B. <u>The proposed scenarios for using hydrogen in the power sector represent a skewed perspective because they both include far more reliance on hydrogen than is likely in a least-cost decarbonization pathway.</u>

The IEPR should not misleadingly label either of these scenarios as involving "low" hydrogen use and should include at least one scenario that resembles the more plausible economic dispatch modeling from the 2022 Scoping Plan update. In all scenarios, the IEPR's projections for the potential use of hydrogen in the electric sector should be consistent with economics and achievement of California's air quality and environmental justice policies.

1. *The proposed "high" scenario ignores the ability of resources other than hydrogen to displace fossil gas at lower cost and California policies that demand the retirement of combustion resources.*

The proposed "high" scenario is not realistic because it ignores the existence of lower-cost alternatives to hydrogen and multiple state policies that demand a transition away from combustion generation resources. While Earthjustice appreciates the CEC discussing alternatives to the Scoping Plan's inclusion of fossil gas on the power grid in 2045, the assumption that hydrogen could displace all fossil gas in the Scoping Plan Scenario ignores the likelihood that other resources would help meet the power grid's needs more economically. Indeed, since the 2022 Scoping Plan update, solar and battery storage deployment have increased substantially.[51] Data from the Lawrence Berkeley National Lab and the CAISO Master Generating Capability List show that solar builds in CAISO have exceeded 3,000 MW per year starting in 2023.[52] For a more informative exercise, the CEC could run a scenario in the Scoping Plan's electricity

---

[49] Michael Liebreich, Hydrogen Ladder Version 5.0, *supra*. Note that Mr. Liebreich predicts hydrogen would be deployed as ammonia or methanol in shipping and as e-fuel or power and bio to liquid ("PBTL") fuel in jet aviation.
[50] UKCCC Seventh Carbon Budget at 146, https://www.theccc.org.uk/wp-content/uploads/2025/02/The-Seventh-Carbon-Budget.pdf. The supporting documents for this report include ERM, ZEV HDV Uptake Trajectories: Modeling Assumptions (2024), https://www.theccc.org.uk/wp-content/uploads/2025/02/ZEV-HDV-uptake-trajectories-ERM.pdf.
[51] *See*, *e.g.*, California ISO, 2023 Special Report on Battery Storage (July 16, 2024) at 4-8, https://www.caiso.com/documents/2023-special-report-on-battery-storage-jul-16-2024.pdf; Joseph Webster and Natalia Storz, Batteries are charging California's solar revolution, https://www.atlanticcouncil.org/blogs/energysource/batteries-are-charging-californias-solar-revolution/.
[52] Barbose et la, Tracking the Sun (Aug. 2024), https://emp.lbl.gov/tracking-the-sun/; Seel et al, (Oct. 20204) https://emp.lbl.gov/utility-scale-solar; http://oasis.caiso.com/mrioasis/logon.do.

sector modeling that excludes fossil gas as a resource in 2045 to see how much hydrogen might economically dispatch in the absence of fossil gas. These considerations are essential because the IEPR's hydrogen demand estimates will only be useful to policymakers if they reflect hydrogen's plausible economic potential.

Moreover, any modeling exercise should include constraints that reflect California's air quality and environmental justice policies. As discussed above, many Californians live in air basins that cannot attain health-based air quality standards without "widespread adoption of zero emissions (ZE) technologies across all mobile sectors and stationary sources, large and small."[53] The CEC's modeling should exclude hydrogen combustion turbines from operating in non-attainment areas because these turbines cannot achieve zero-emissions. Scoping Plan data on gas combustion does not provide a reasonable upper bound for the sector's potential hydrogen demand because the Scoping Plan does not consider air quality mandates.

Similarly, assuming hydrogen combustion will replace all methane combustion would be inconsistent with California's transmission planning and energy justice policies. In SB 887, the Legislature declared that it is a problem that "there are load pockets where there is insufficient transmission capacity to import the renewable energy resources and zero-carbon resources that are available" and established transmission planning mandates to fix this problem.[54] Improved transmission will substantially reduce the need to rely on polluting resources in California's constrained load pockets. The Scoping Plan does not consider these policies.

2. *The so-called "low" scenario artificially inflates demand for hydrogen with the unjustified assumption that hydrogen will displace half the power generation from new geothermal resources.*

As in the 2023 IEPR, CEC staff proposes to rely on a UC Irvine study for a "low" bookend for hydrogen demand in the power sector. Although the staff presentations and 2023 IEPR do not cite to a specific UC Irvine report, they appear to refer to a 2020 publication called Renewable Hydrogen Production Roadmap for California.[55] Policymakers should be cautious about relying on this report for projections about hydrogen demand in the electric sector because it does not explain its estimate for that sector's use of hydrogen. Indeed, the report barely discusses the role of hydrogen in electricity generation at all. It only mentions that sector in passing on two pages, where it makes cursory generalizations about hydrogen being well-suited for long-duration energy storage.[56] We appreciate that CEC staff explained at the July 29 workshop how UC Irvine developed its estimate for hydrogen demand in the power sector: it

---

[53] South Coast Air Quality Management District, 2022 Air Quality Management Plan, at ES-5.
[54] Cal. Public Utilities Code § 454.57(b)(3), -(d)–(f) (codifying SB 887 (2022)).
[55] Available at https://www.apep.uci.edu/PDF_White_Papers/Renewable_Hydrogen_Production_Roadmap_For_California_061920_11am.pdf.
[56] *Id.* at 9, 10.

assumed hydrogen would be used to replace half of the new long-duration energy storage and half the grid power from geothermal resources as forecast in the California Public Utilities Commission's ("CPUC") 2018 RESOLVE planning model.[57] There is no justification for assuming that half of the energy needs that geothermal resources could economically meet might rationally be met by burning hydrogen. In fact, policymakers should expect geothermal and hydrogen resources to play very different roles on the electric grid. Geothermal resources have higher capacity factors than any other kind of renewable resource.[58] In contrast, the production cost modeling for the 2022 Scoping Plan update indicates that hydrogen resources will rarely economically dispatch and, consequently, have very low capacity factors. The flawed assumption that hydrogen displaces half the electricity generation from California's new geothermal resources is a serious problem that skews the study's projected hydrogen demand.[59]

3. *The CEC has multiple options for developing a more plausible scenario, and failing to do so would deprive decisionmakers of important information.*

The IEPR should take advantage of the 2022 Scoping Plan update's economic dispatch modeling to understand the power sector's likely hydrogen demand in a least-cost scenario. In that modeling, the power sector used zero hydrogen, even though a significant amount of hydrogen generation resources were available to provide capacity in emergency events. That is, the modeling shows that most economical route for achieving power sector goals might require zero hydrogen for grid power. The 2025 IEPR should acknowledge this dynamic. It may be useful to model how much hydrogen is used in a hypothetical n-1 event.

Alternatively, the CEC could use a similar strategy to the UC Irvine researchers to estimate hydrogen demand in the electricity sector, but correct the fundamental flaws in the UC Irvine methodology. That is, the CEC could seek recent modeling from the CPUC on the future electricity mix and assume that hydrogen provides some reasonable level of the forecasted need long-duration energy storage. A reasonable scenario would not assume that hydrogen displaces any generation from geothermal resources, which have distinct performance and cost profiles.

---

[57] July 29 workshop recording at around 4:58:55.

[58] U.S. Energy Information Administration, Nearly half of U.S. geothermal power capacity came online in the 1980s (Nov. 20, 2019), https://www.eia.gov/todayinenergy/detail.php?id=42036.

[59] Although Earthjustice is unaware of the level of long-duration energy storage and geothermal in the CPUC modeling exercise that the UC Irvine study used, the RESOLVE modeling that supports the Commission's most recent Transmission Planning Process forecasts greater capacity procurements from geothermal resources than long-duration energy storage resources. If the relationship between geothermal and long-duration energy storage were similar in the modeling UC Irvine relied on, then the decision to substitute hydrogen for geothermal resources (in addition to long-duration energy storage resources) would more than double the forecasted demand for hydrogen-fired generation. CPUC, Proposed Electricity Resource Portfolios for the 2023-2024 Transmission Planning Process (Oct. 20, 2022), at slide 17, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/2023-2024-tpp-portfolios-and-modeling-assumptions/23-24tpp_portfolios_workshopslides.pdf.

Another way to develop an appropriate lower-bound scenario would be to accept the Scoping Plan's finding that no hydrogen resources would be economically dispatched and limit the role of hydrogen to meeting other electricity needs. For instance, hydrogen and hydrogen derivatives can provide mobile power with existing technology, without the extraordinary infrastructure investments discussed in the CEC staff presentations.[60] In addition to Kaizen, other companies are competing to offer large-scale fuel cells that can hasten electrification of the transportation sector by enabling high-power charging in remote locations or areas where lengthy grid-upgrades may still be required.[61] Fuel cells can also be incorporated into microgrids to improve reliability and resiliency. In Calistoga, 8 MW of hydrogen fuel cell stationary power will supplement lithium-ion batteries in a microgrid to replace diesel generators and supply the city's electricity needs for at least 48 hours during outages.[62] These power generation technologies could be deployed throughout California because they are zero-NOx. As the technologies scale, prices are likely to decline faster for mass produced products like fuel cells and electrolyzers than for complex and customized systems like power plant retrofits.[63] Information on the potential for zero-NOx long-duration energy storage options—including hydrogen technologies—will be critical for California policymakers and should be the focus of at least one demand scenario.

C. <u>The proposed hydrogen production scenarios rely on polluting technologies that threaten achievement of California's public health and climate policies and assume the mismanagement of scarce resources.</u>

Earthjustice urges the CEC to revisit certain assumptions related to hydrogen production underlying the proposed SB 1075 analysis. Correcting these assumptions will help California plan a least-cost energy transition and align the CEC's SB 1075 analysis with state climate and public health goals.

1. *Hydrogen production locks in dependence on fossil fuels in all scenarios, based on an unreasonable assumption that widespread fossil hydrogen production is consistent with California's climate and public health policies.*

All the proposed scenarios in the hydrogen production analysis include significant amounts of blue hydrogen, with a whopping 40% or hydrogen production relying on fossil fuels in the scenario the staff refers to as "balanced."[64] This raises an alarm that a California economy

---

[60] *See*, *generally*, workshop presentation of Craig Klassmeyer on behalf of Kaizen Clean Energy.
[61] *See* Nora Manthey, "Plug Power Presents Stationary Fuel Cell System to Charge BEVs" (May 3, 2023) https://www.electrive.com/2023/05/03/plug-power-presents-stationary-fuel-cell-system-to-charge-bevs/#:~:text=Plug%20Power%20is%20looking%20to,provides%2060%20MWh%20on%20site.
[62] Kathy Hitchens, "Plug Power to Provide Hydrogen Fuel Cell for Calistoga Microgrid" (June 12, 2023) https://www.microgridknowledge.com/generation-fuels/article/33006510/plug-power-to-provide-hydrogen-fuel-cell-for-calistoga-microgrid.
[63] *See* Abhishek Malhotra and Tobias S. Schmidt, Accelerating Low-Carbon Innovation, Vol. 4 Joule 2259 (Nov. 2020), https://www.sciencedirect.com/science/article/pii/S2542435120304402.
[64] CEC Staff presentation at slide 11.

that relies on hydrogen for significant amount of its energy needs could lock in dependence on fossil fuels, drive health-harming pollution in disadvantaged communities ("DACs"), and fail to achieve climate goals.

The IEPR modeling should not include fossil-based hydrogen production plays a role in California's future because it would be irresponsible to assume that blue hydrogen can be produced in a manner that aligns with California's climate goals. The International Renewable Energy Agency has warned that blue hydrogen can "yield very low greenhouse gas emissions, only if methane leakage emissions do not exceed 0.2%, with close to 100% carbon capture. Such rates are still to be demonstrated at scale."[65] Currently, the upstream emissions of California's fossil gas supply is more than an order of magnitude greater than this target level. On average, fossil gas consumed in California has a production-stage methane leakage rate of 2.8%, according to Burns and Grubert.[66] More recent analyses, including one that conducts a similar model to Burns and Grubert using an alternate approach and one that evaluates airborne methane surveys, confirm these high production-stage leakage rates for California gas – well over the 0.2% target.[67] Further, blue hydrogen facilities with close to 100% carbon capture continue to be non-existent at scale. Researchers explain that to achieve such levels, "hydrogen production and CO_2 capture must be designed in an integrated way to minimize additional energy demand for CO_2 capture, as well as compression of hydrogen and CO_2."[68] In other words, high carbon capture at blue hydrogen facilities will only feasibly exist at entirely new projects, rather than retrofits of existing facilities—requiring significant investments in new fossil fuel infrastructure that may become stranded assets if the realization comes too late that widespread fossil fuel dependency is inconsistent with meeting California's ambitious climate goals. To achieve low emissions blue hydrogen, *both* upstream methane leakage must be minimized and carbon capture must be maximized.[69] Right now, neither is easily achieved. If the fossil fuel industry fails to abate its enormous upstream emissions and achieve nearly 100% carbon capture at scale, relying on fossil methane for hydrogen production will undermine the State's ability to achieve its climate goals at a reasonable cost.

Blue hydrogen relies on carbon capture and sequestration ("CCS"), which poses significant air pollution, water usage, water pollution, and safety risks. Given that California's fossil-based hydrogen production infrastructure is sited in the same DACs as the oil refineries

---

[65] IRENA, Geopolitics of the Energy Transformation: The Hydrogen Factor (2022), at 8 (footnote omitted).
[66] Diana Burns & Emily Grubert, *Attribution of production-stage methane emissions to assess spatial variability in the climate intensity of US natural gas consumption*, at 6, 16 Environmental Research Letters 4 (2021), https://iopscience.iop.org/article/10.1088/1748-9326/abef33.
[67] James Littlefield et. al., *Life Cycle GHG Perspective on U.S. Natural Gas Delivery Pathways*, at 16,039, Environmental Science & Technology 56 (2022), https://pubs.acs.org/doi/10.1021/acs.est.2c01205?ref=PDF; Evan Sherwin et. al., *US oil and gas system emissions from nearly one million aerial site measurements*, at 331, Nature Vol. 627 (2024), https://www.nature.com/articles/s41586-024-07117-5.
[68] Christian Bauer et. al., *On the climate impacts of blue hydrogen production,* at 71, Sustainable Energy & Fuels 6 (2022), https://pubs.rsc.org/en/content/articlelanding/2022/se/d1se01508g.
[69] EDF, Nichole Saunders, Getting to clean: The carbon capture imperative for blue hydrogen (May, 2025), https://blogs.edf.org/energyexchange/2025/05/16/getting-to-clean-the-carbon-capture-imperative-for-blue-hydrogen/.

that use the hydrogen, there is a clear risk that pairing CCS with fossil-based hydrogen production will disproportionately burden these DACs with new risks. If the IEPR considers pathways with CCS, it must account for the following potential impacts:

- Carbon capture systems do not necessarily capture other types of hazardous pollutant emissions, and the solvents involved in the process may create new air and water pollution impacts.[70]
- Carbon capture systems increase water consumption at a facility.[71]
- Carbon dioxide pipelines pose various environmental and health threats. Carbon dioxide's interaction with impurities, such as water and hydrogen sulfide, can compromise pipe integrity and increase the risk of corrosion and failure, which could lead to the re-release of carbon dioxide into the atmosphere and lead to a public health emergency because carbon dioxide is an asphyxiant.[72]
- Long-term carbon dioxide sequestration via saline aquifers poses various environmental threats, including potential contamination of shallow aquifer waters and leakage of carbon dioxide back into the atmosphere.[73]

In sum, the IEPR should not assume reliance on fossil hydrogen. If it does, the CEC should carefully examine all the climate and public health risks of this strategy.

2. *The proposed scenarios unreasonably assume hydrogen production from biomethane, which is an irrational use of scarce biomethane resources and an avoidable source of health-harming pollution.*

In all scenarios, the CEC staff propose an assumption that 6% of hydrogen production relies on biomethane.[74] In the IEPR, the CEC should revise its approach and not include any

---

[70] A report seeking to project air pollution reductions from adding CCS at dirty facilities found that NOx emissions may be lowered by only 2% with the addition of CCS and that VOCs may increase by 14% as a result of the capture solvents, without even accounting for the energy penalty of the system. *See* Clean Air Task Force, Air Pollutant Reductions from Carbon Capture, at 10–11 (Dec. 1, 2023), https://www.catf.us/resource/air-pollutant-reductions-carbon-capture/. *See also*, Yukyan Lam et al., Environmental Justice Concerns with Carbon Capture and Hydrogen Co-Firing in the Power Sector, The New Sch. Tishman Env't and Design Ctr.(June 2024), https://njeja.org/wp-content/uploads/2024/07/CCS-EJ-White-Paper.pdf; Reynolds et al., *Towards Commercial Scale Postcombustion Capture of CO2 with Monoethanolamine Solvent: Key Considerations for Solvent Management and Environmental Impacts*, 46 Env. Sci. & Tech. 3643-3654 (2012) https://pubs.acs.org/doi/10.1021/es204051s; Veltman et al., *Human and Environmental Impact Assessment of Postcombustion CO2 Capture Focusing on Emissions from Amine-Based Scrubbing Solvents to Air*, 44 Env. Sci. & Tech. 1496-1502 (2010), https://pubs.acs.org/doi/10.1021/es902116r.
[71] Lorenzo Rosa et al., The water footprint of carbon capture and storage technologies, 138 Renewable & Sustainable Energy Revs. 110511 (2021), https://doi.org/10.1016/j.rser.2020.110511.
[72] Richard Kuprewicz, Accufacts' Perspectives on the State of Federal Carbon Dioxide Transmission Pipeline Safety Regulations as it Relates to Carbon Capture, Utilization, and Sequestration within the U.S., prepared for the Pipeline Safety Trust (Mar. 23, 2022), https://pstrust.org/wp-content/uploads/2022/03/3-23-22-Final-Accufacts-CO2-Pipeline-Report2.pdf.
[73] Hannah Klaus et al., Uncertainties and Gaps in Research on Carbon Capture and Storage in Louisiana, Ctr. for Progressive Reform (June 2023), https://cpr-assets.s3.amazonaws.com/wp/uploads/2023/06/ccs-in-louisiana-rpt-june2023-final.pdf.
[74] CEC Staff presentation at slide 11.

hydrogen production with biomethane feedstocks. Converting biomethane to hydrogen is irrationally wasteful and, ultimately, would unnecessarily increase the costs of achieving California's ambitious climate policies. Producing hydrogen from methane also emits health-harming pollution such as NOx and particulate matter.[75]

Responsibly sourced biomethane is a scarce resource that should not be squandered on hydrogen production. Even under the gas industry's most ambitious projections, methane derived from purported waste streams could only replace about 9% of the fossil gas the United States currently uses.[76] In the industry's low-resource potential scenario, biogenic waste products could supply less than half of that.[77] The gas industry calculations likely include biomethane that was deliberately created in response to incentives from the biomethane commodity market. California should ensure that its climate policies minimize the creation of biomethane and use any truly unavoidable biomethane judiciously.

The process of converting biomethane to hydrogen inherently involves energy losses. When producing hydrogen from methane via steam reformation, those losses can represent about 30% of the energy in the methane.[78] It would make no sense to waste energy by converting biomethane into hydrogen rather than simply using the biomethane. For instance, using biomethane to generate electricity in a fuel cell instead of converting that biomethane into hydrogen to power the fuel cell would yield more useful energy, avoid the polluting process of steam methane reformation, and could reduce cost and implementation time by decreasing complexity. The IEPR should recognize that a rational economywide resource plan will likely direct biomethane toward more efficient uses than hydrogen production.

---

[75] Pinping Sun et al., Criteria Air Pollutants and Greenhouse Gas Emissions from Hydrogen Production in U.S. Steam Methane Reforming Facilities, Env't Sci. & Tech., Vol. 53 Issue 12, (Apr. 30, 2019), https://www.osti.gov/pages/servlets/ purl/1546962.

[76] American Gas Foundation, Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment (Dec. 2019), at 3, https://www.gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Executive-Summary-Final-12-18-2019-AS-1.pdf. The AGF Study estimates total resource potential in 2040 to be 3,780 tBtu in a High Resource Potential Scenario that includes P2G/methanation and growing more energy crops. Excluding P2G/methanation and energy crops, the High Resource Potential Scenario projects about 3,000 tBtu of biomethane production in 2040. According to the U.S. Energy Information Administration ("U.S. EIA"), total US Gas Consumption in 2023 equals 33,610 tBtu. U.S. EIA, Natural Gas Explained, https://www.eia.gov/energyexplained/natural-gas/useof-natural-gas.php (last visited Mar. 12, 2024). Therefore, biomethane production from waste in the High Resource Potential Scenario represents about 9% of current fossil gas usage (3,000 tBtu / 33,610 tBtu).

[77] American Gas Foundation, Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment, *supra*, at 3.

[78] Christos Kalamaras et al., Hydrogen Production Technologies: Current State and Future Developments, Conf. Papers in Sci. (2013), https://doi.org/10.1155/2013/690627.

3. *The IEPR should assume agricultural biomass in the San Joaquin Valley is not available for hydrogen production because it is used consistent with air quality and sustainability policies.*

In the CEC staff's proposed scenarios, biomass gasification produces 9–14% of California's hydrogen supply.[79] Relying on biomass resources for energy presents several challenges to air quality, climate, and sustainable agriculture policies, which Earthjustice discusses in the next section. We urge the CEC to ensure that each of its hydrogen production scenarios align with policy goals. For instance, it should not model NOx or PM-emitting industrial processes in the heavily polluted air basins where regulators have acknowledged that meeting health-based air quality standards without a widespread transition to zero-emissions technologies across large and small stationary sources.[80] Similarly, the modeling should assume that agricultural biomass is reincorporated in the soil through the sustainable practices that the San Joaquin Valley Air Pollution Control District is incentivizing.

III. The CEC Must Consider Emissions Impacts, Cost, and Alternative Uses of Biomass when Assessing Its Value Proposition

In considering the value proposition of biomass resources, the IEPR should recognize that using woody biomass as a fuel does not have a proven climate benefit, that California policies appropriately prioritize more sustainable uses of agricultural wastes, and that the health harms of producing energy from biomass undercuts its value as a resource. It should also acknowledge that the exorbitant costs of biomass use have made it uneconomical in most circumstances.

A. Climate impacts of using woody biomass for energy

It would be incorrect for the IEPR to characterize forest biomass as a carbon-neutral resource. A recent scientific review summarized the significant literature that shows widespread forest thinning to reduce fire severity leads to more carbon emissions than wildfire, "creating a multi-decade carbon deficit that conflicts with climate goals."[81] In California's megafires, carbon emissions represented only about 0.1–3.2% of stand-level carbon and 0.6–1.8% of landscape-level carbon because most of biomass is in larger trees with low combustion rates.[82] Harvest-related emissions in California and other western states are about 5 times that of fire emissions.[83] Thinning is also not a reliable climate mitigation strategy because it causes high forest carbon

---

[79] CEC Staff presentation at slide 11.
[80] South Coast Air Quality Management District, 2022 Air Quality Management Plan, *supra*.
[81] Beverly E. Law et al, The Status of Science on Forest Carbon Management to Mitigate Climate Change and Protect Water and Biodiversity (Mar. 9, 2022), at 4, https://coastrange.org/wp-content/uploads/2023/05/Status-of-Science-on-Forest-Carbon-Management_031722.pdf.
[82] *Id.*
[83] *Id.* at 5.

losses, but there is a "low likelihood that thinned forests will be exposed to fire during treatment effectiveness."[84] Even if a fire does occur after thinning, scientists have observed "only minor differences in the combustive losses" that thinning is meant to address.[85]

To understand the real climate impacts of relying on biomass for fuel, the IEPR would need to consider all sources of climate pollution in a complete lifecycle analysis for pathways that rely on biomass. This lifecycle analysis would include the following:

- Storing harvested biomass in piles results in carbon emissions that would not have occurred had the material not been harvested in the first place. When forest residues are scattered across the forest floor, without creating deep layers or piles of material, they are unlikely to produce methane emissions. In contrast, significant methane emissions are released by the log landings and wood chip piles that are part of the biomass to energy supply chain.[86]
- The biomass must be transported to the location where it will be used as a feedstock for fuel production, which will have associated carbon emissions and air pollutant impacts. For instance, when Pacific Gas & Electric Company proposed a biomass-to-methane pilot project at the CPUC, it estimated that truck deliveries of biomass to the facility would require an average of 2,700 vehicle miles per year and a maximum of 9,000 vehicle miles per year.[87] Based on this information, the CPUC's Public Advocates Office estimated that the pilot's biomass transportation alone would incur 3.79 to 12.65 metric tons of carbon dioxide alone.[88] The CPUC rejected the pilot proposal earlier this year because the utility failed to demonstrate that it would reduce greenhouse gas emissions.[89]

---

[84] *Id.* at 4.
[85] *Id.*
[86] Research indicates that methane emissions from wood chip piles at biomass facilities can be large enough to significantly add to the overall GHG impact of bioenergy production. *See, e.g.*, Margareta Wihersaari, Evaluation of greenhouse gas emission risks from storage of wood residue, 28 Biomass & Bioenergy 444 (2005), https://www.sciencedirect.com/science/article/abs/pii/S0961953404002144; Carly Whittaker et al., Dry Matter Losses and Methane Emissions During Wood Chip Storage: the Impact on Full Life Cycle Greenhouse Gas Savings of Short Rotation Coppice Willow for Heat, 9 Bioenergy Rsch. 820 (2016), https://link.springer.com/article/10.1007/s12155-016-9728-0; Juliana Vantellingen et al., Log landings are methane emissions hotspots in managed forests, 51 Can. J. of Forest Rsch. 1916 (2021), https://cdnsciencepub.com/doi/abs/10.1139/cjfr-2021-0109.
[87] Application 23-06-023, Testimony on Pacific Gas and Electric Company's Application for Approval of the Woody Biomass to Renewable Natural Gas Pilot Project (Feb. 16, 2023), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M529/K871/529871040.PDF (page 4 of Attachment).
[88] *Id.* at 5.
[89] CPUC Decision 25-05-003 (May 21, 2025), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M566/K975/566975547.PDF.

- Biomass-to-energy facilities create waste products such as biochar that can cause additional greenhouse gas emissions, depending on how the material is stored, applied to the land, or hauled for disposal or other use.[90]
- Woody biomass is usually pelleted prior to being used as a feedstock for fuel production, a process that involves heat for drying and electricity input, both of which have carbon emissions and other air pollutant impacts.[91]
- Leakage of methane and/or hydrogen at the energy conversion facility could negate any climate benefits from using biomass to produce fuel. At leakage rates between 5-6.6%, biomethane from intentionally produced methane can be more GHG intensive than fossil gas.[92]
- If biomass is converted to methane or hydrogen, these climate-destabilizing gases will leak downstream of the conversion facility. For instance, a facility that produces methane from biomass may inject that methane into California's gas pipeline system, which CARB estimates to have a leakage rate of 0.7%.[93] This is an optimistic estimate, as recent studies measuring methane emissions in California have shown higher rates of leakage from behind-the-meter appliances alone.[94]

B. Soil reincorporation provides the greatest environmental value for agricultural biomass

The IEPR should recognize that reincorporating agricultural biomass into the soil is a more sustainable and higher priority use of this resource than energy production. California's most productive agricultural region is in the San Joaquin Valley, which has banned almost all burning of agricultural residue.[95] In general, the a more sustainable use for this agricultural waste

---

[90] *See, e.g.*, Semra Bakkaloglu et al., (July 2022) https://www.cell.com/one-earth/pdf/S2590-3322(22)00267-6.pdf (noting the digestate storage and handling stage generated the most methane emissions.)
[91] *See, e.g.*, Mirjam Röder et al., How certain are greenhouse gas reductions from bioenergy? Life cycle assessment and uncertainty analysis of wood pellet-to-electricity supply chains from forest residues, 79 Biomass and Bioenergy 50 (2015),10.1016/j.biombioe.2015.03.030.
[92] Emily Grubert, At Scale, Renewable Natural Gas Systems Could be Climate Intensive: The Influence of Methane Feedstock and Leakage Rates, Envtl. Research Letters (2020), https://doi.org/10.1088/1748-9326/ab9335.
[93] CPUC, 2022 Distributed Energy Resources Avoided Cost Calculator Documentation (June 2022) at 59 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2022-acc-documentation-v1a.pdf.
[94] Eric D. Lebel et al., Methane and NOx Emissions from Natural Gas Stoves, Cooktops, and Ovens in Residential Homes (2022) https://pubs.acs.org/doi/10.1021/acs.est.1c04707 (finding a post-meter methane leakage rate of 0.8-1.3% in natural gas stoves in a study of 53 California houses); Eric D. Lebel et al., Quantifying Methane Emissions from Natural Gas Water Heaters (Apr. 2020) https://pubs.acs.org/doi/10.1021/acs.est.9b07189 (finding gas water heaters in Northern California homes leaked 0.39-0.93% of the gas they consumed).
[95] San Joaquin Valley Air District, "Updated Phase-Out Schedule for Agricultural Burning" (Sept. 3, 2021) at 1, https://ww2.valleyair.org/media/tgmjc12b/agburninginfographics_lettersize-2x09032021.pdf ("all operations prohibited from burning all sizes of removals except in cases of disease and pest concerns.").

is for it to be chipped and reincorporated into the soil on-site as a soil amendment that can help with water retention and soil carbon sequestration.[96] Mulching or leaving this waste on the ground can help control erosion, conserve soil moisture, remove harmful heavy metals, and minimize the need for pesticides and herbicides, among other benefits.[97] Under a CARB-approved plan, the San Joaquin Valley Air Pollution Control District is providing incentives for beneficial uses of agricultural residue that prioritizes the practices that provide the most environmental benefits.[98] Bioenergy activities such as pyrolysis are not eligible for these incentives.[99] The IEPR should assume that California's air regulators are successful in their efforts to shift industry practices toward reincorporating agricultural residues into soil. The CEC should also explicitly recognize that using agricultural waste for energy production comes at the opportunity cost of using it on the land, which means foregoing both the climate benefits of carbon sequestration in the soil and a range of other environmental and public health benefits.

C. Health impacts of gasification and pyrolysis

Biomass gasification or pyrolysis facilities release significant health-harming pollution. There is robust scientific evidence that the process to gasify or pyrolyze biomass creates myriad air pollutants, including: NOx, SOx, benzene, toluene and xylenes, tars and soot, PM 2.5, and persistent organic pollutants such as polycyclic aromatic hydrocarbons (e.g., naphthalene), polychlorinated dibenzo-*p*-dioxins and dibenzofurans;[100] and NOx precursors.[101] The gasification of biomass can also generate hazardous waste.[102] As indicated above, trucking the

[96] Emad Jahanzad et al., Orchard Recycling Improves Climate Change Adaptation and Mitigation Potential of Almond Production Systems (Mar. 2020), https://doi.org/10.1371/journal.pone.0229588.
[97] Andrews, S.S., Crop residue removal for biomass energy production: Effects on soils and recommendations (2006); Xu, H. et al., A global meta-analysis of soil organic carbon response to corn stover removal, 11 Global Change Bioenergy 1215 (2019); Iqbal, R. et al., Potential agricultural and environmental benefits of mulches—a review, 44 Bulletin of the National Research Centre (2020).
[98] CARB, Staff Report: Agricultural Burning Alternatives Analysis Report (Oct. 8, 2021), https://ww2.arb.ca.gov/sites/default/files/2021-10/Agricultural_Burning_Alternatives_Analysis_Report.pdf.
[99] San Joaquin Valley Air Pollution Control District, Ag Burn Alternatives Grant Program, at 3, https://ww2.valleyair.org/media/e3smmq1x/ag-burn-alternatives-grant-program-guidelines-and-application-january-2025-rev-3-25.pdf.
[100] Wu-Jun Liu et al., Fates of Chemical Elements in Biomass During Its Pyrolysis, 117 Chem. Reviews 6367 (2017), https://pubs.acs.org/doi/10.1021/acs.chemrev.6b00647; Zhiyi Yao et al., Particulate emissions from the gasification and pyrolysis of biomass: Concentration, size distributions, respiratory deposition-based control measure evaluation, 242 Env't Pollution 1108 (2018), https://doi.org/10.1016/j.envpol.2018.07.126; Jennie Perey Saxe et al., Just or bust? Energy justice and the impacts of siting solar pyrolysis biochar production facilities, 58 Energy Rsch. & Soc. Sci. 101259 (2019) https://doi.org/10.1016/j.erss.2019.101259; Simeng Li, Reviewing Air Pollutants Generated during the Pyrolysis of Solid Waste for Biofuel and Biochar Production: Toward Cleaner Production Practices, 16 Sustainability 1169 (2024), https://doi.org/10.3390/su16031169.
[101] Hongyuan Chen et al., A review on the NOx precursors release during biomass pyrolysis, 451 Chem. Eng'g J. 138979 (2023), https://doi.org/10.1016/j.cej.2022.138979.
[102] Farooq Sher et al., Cutting-edge biomass gasification technologies for renewable energy generation and achieving net zero emissions, 323 Energy Conversion & Mgmt. 1 (Jan. 1, 2025), https://www.sciencedirect.com/science/article/pii/S0196890424011543#:~:text=It%20is%20found%20that%20optimizing,adoption%20in%20the%20global%20market; Neil Tangri et al., GAIA, Wast Gasification & Pyrolysis: High

biomass to a gasification or pyrolysis facility would be another significant source of pollution and disruption to the neighboring community. As explained above, the Pacific Gas & Electric Company woody-biomass-to-methane pilot project rejected by the CPUC would have entailed up to 9,000 diesel truck miles per year, emitting toxic and carcinogenic diesel particulate matter and other pollutants into nearby communities.[103] The health harms of converting biomass to fuel via gasification and pyrolysis undercuts the purported value proposition of this energy resource.

Few biomass gasification or pyrolysis facilities currently exist in the United States for the purpose of producing hydrogen. Project developers have frustrated the public's ability to understand the air pollution impacts of biomass gasification for hydrogen production by characterizing their criteria pollution emissions as proprietary information.[104] Even if the developers' estimates regarding emissions from future projects were publicly available, there would be a significant risk that they would underestimate project emissions.[105]

D. The high monetary cost of using biomass for energy

The CEC should consider the exorbitant costs associated with using biomass for energy. The history of the CPUC's the Bioenergy Market Adjustment Tariff ("BioMAT") program is illustrative, demonstrating that biomass projects are expensive for ratepayers, with little if any pay off for the climate, air quality, or ratepayers. Over ten years since it launched, the BioMAT program remains undersubscribed and extremely costly.[106] Indeed, Pacific Gas & Electric Company recently opposed the Bioenergy Association of California's attempt to extend the program, citing cost concerns.[107] Further, as noted above, the CPUC recently rejected Pacific Gas & Electric Company's biomass pilot project which, as indicated in Sierra Club's briefing on the application, would have imposed excessive costs per MMBtu that were neither just nor

---

Risk, Low Yield Processes for Waste Management (Mar. 2017), https://www.no-burn.org/wp-content/uploads/Waste-Gasification-and-Pyrolysis-high-risk-low-yield-processes-march-2017.pdf.

[103] California Public Utilities Commission proceeding Application 23-06-023, Prepared Testimony of Ranajit (Ron) Sahu and Sasan Saadat on Behalf of Sierra Club on the Application of PG&E for Approval of Its Woody Biomass to Methane Pilot Project (U39G), (Feb. 16, 2024) at 25:18-24.
https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2306023/7054/525583319.pdf at 25 (citing CARB, Overview: Diesel Exhaust and Health https://ww2.arb.ca.gov/resources/overview-diesel-exhaust-and-health).

[104] Alliance for Renewable Clean Hydrogen Energy Systems, ARCHES Technical Submission to DOE, at 82 (Apr. 2023), https://archesh2.org/wp-content/uploads/2024/08/ARCHES-Technical-Volume-Redacted.pdf ("GHG emissions and criteria air pollutants emissions for biomass facilities are proprietary data, and include diesel truck biomass transport, diesel truck waste transport, PPA-solar electricity, natural gas, chemical feedstock life cycles, CO2 treatment compression and sequestration, hydrogen conditioning and direct emissions from the facility.").

[105] For instance, Pacific Gas & Electric Company proposed a biomass gasification facility and underestimated its air emissions in several ways, such as failing to account for fugitive emissions. California Public Utilities Commission proceeding Application 23-06-023, Prepared Testimony of Ranajit (Ron) Sahu and Sasan Saadat on Behalf of Sierra Club on the Application of PG&E for Approval of Its Woody Biomass to Methane Pilot Project (U39G), at 10:13–11:20 (Feb. 16, 2024), https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2306023/7054/525583319.pdf.

[106] *See, e.g.*, CPUC, Bioenergy Market Adjustment Tariff (BioMAT): AB 843 Implementation Workshop at Slide 14 (Apr. 28, 2023), https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/documents/energy/rps/ab-843-workshop_04282023.pdf (only 48.8 contracted capacity of 250 MW program total with contracted price of forest waste at $199.72/MWh and biogas from diverted waste at $127.72/MWh). a

[107] R.18-07-003, PG&E Response to BAC Petition to Modify Decision 20-08-043 (April 7, 2025) at 2, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M562/K084/562084633.PDF.

reasonable.[108] Notably, a 2020 CEC study found that even under optimistic cost projections, the cost of methane produced synthetically such as through thermal gasification of biomass to syngas would be 8 to 17 times more expensive than the expected price trajectory of fossil gas.[109]

In a related vein, the CPUC's biomethane procurement program has not resulted in any procurement of methane derived from biomass, and the few procurement contracts that have been submitted have raised cost concerns. For instance, the CPUC recently rejected two landfill methane contracts finding that it "agrees with Sierra Club that 'the cost of this biomethane is not justified' for this landfill gas procurement opportunity and goes further to say that price would be a significant barrier to approval even if this type of procurement was allowed at this point in the program."[110] Tellingly, in comments submitted to the CPUC about its biomethane procurement program, the Coalition for Renewable Natural Gas admitted that "the Commission should not expect cost declines to the degree seen historically in other renewable technologies, such as solar and wind," and that "significant cost declines are not expected" for biomethane production.[111]

Thus, the CEC must carefully scrutinize the costs of biomass use when assessing its value proposition as a fuel. Given California's current energy affordability crisis, it would be improper to ignore the high financial cost of using biogenic materials for energy.

Conclusion

Thank you for the opportunity to comment on the July 29 IEPR workshop. Earthjustice would be happy to continue collaborating with CEC as they refine the analysis in the 2025 IEPR.

Sincerely,

Sara Gersen
Earthjustice

---

[108] Sierra Club, Reply Brief (public version) (May 29, 2024) at 9-11. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M533/K099/533099082.PDF.
[109] Aas et al., The Challenge of Retail Gas in California's Low-Carbon Future (April 2020) at 4, https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-F.pdf.
[110] CPUC Resolution G-3612 (redacted version) at 9, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M557/K879/557879266.PDF (quoting Sierra Club Protest to SoCalGas AL 6316-G at 2.),
[111] CPUC, R.13-02-008, RNG Coalition, Opening Comments on Assigned Commissioner's Ruling, (July 19, 2024) at 7, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M536/K273/536273401.PDF.