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See attached comments from the International Council on Clean Transportation (ICCT).

November 10, 2025

RE: International Council on Clean Transportation comments on the Proposed Regulatory Action to Amend the LCFS Regulation within California Regulatory Notice Register 2025, Volume # 39-Z, Notice File Number Z2025–0909–05

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 Low Carbon Fuel Standard amendments to allow the use of indirect accounting of renewable natural gas (RNG) for LCFS reporting and crediting of electricity for vehicle charging produced by linear generators. The comments below offer a number of technical observations and suggested amendments to guard against adverse air quality and climate impacts of the proposal.

We would be glad to clarify or elaborate on any points made in the below comments. If there are any questions, ARB staff can feel free to contact Nik Pavlenko (n.pavlenko@theicct.org) and Andy Navarrete (a.navarrete@theicct.org) for questions related to LCFS. Ray Minjares (ray@theicct.org) and Yihao Xie (y.xie@theicct.org) can respond to questions related to heavy-duty vehicles.

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Electrification of heavy-duty vehicles (HDVs) is a critical piece of California's strategy to achieve decarbonization goals such as the AB1279 target of 85% greenhouse gas (GHG) reductions by 2045. In support of this strategy, Governor Newsom recently signed Executive Order N-27-5 reinforcing the statewide goal of fully transitioning medium- and heavy-duty vehicle operations to 100 percent zero-emission vehicles.

As described in the ISOR Appendix F, a current challenge to heavy-duty (HD) battery electric vehicle (BEV) deployment is the timely energization of charging facilities. Due to the power requirements of facilities, especially those above 2 megawatts, distribution system upgrades may take longer than delivery times for new vehicles. This misalignment has reportedly led fleets to postpone or cancel the delivery of battery-electric vehicles. The timely energization of charging facilities is therefore an obstacle to meeting state goals.

A number of technical and policy solutions exist to overcome these challenges. Legislative actions, including AB2700 and SB410, help ensure utilities are planning for transportation electrification. Multiple proceedings led by the California Public Utilities Commission, including on Energization, High Distributed Energy Resources deployment, and on Transportation Electrification Planning and Investment are also advancing solutions that will help investor-owned utilities meet demand from commercial charging facilities in a timely manner.

As these legislative and regulatory policies take effect, gaps remain in near-term solutions to energize large loads within the next five years. One possible solution is on-site electricity generation using fossil fuel powered generators. These generators can be powered by diesel or natural gas fuels and can employ reciprocating engines, fuel cells, or linear generators. Additional distributed energy resources, such as battery-energy storage systems and solar power can also reduce the size of the interconnection request, accelerating the timeline for interconnection, while also providing services back to the grid. In some cases both generators and distributed solutions are installed at a single charging location. Creative solutions like these are already being implemented at sites where grid constraints present barriers to well-financed projects supported by strongly motivated customers.

Because linear generators produce fewer criteria pollutant emissions than reciprocating generators, CARB identifies linear generators as a preferred

method for converting fossil fuels into electricity at HDV charging stations. The current proposal would express this preference by allowing linear generator operators access to book-and-claim renewable natural gas (RNG) credits. Currently this system is only available for direct fueling of natural gas-powered vehicles, RNG used in fuel cells, and RNG used to produce hydrogen.

While Appendix F of the ISOR includes an economic analysis arguing the changes will have no market impact, our analysis suggests that allowing exclusive access for linear generators at HDV charging sites to generate LCFS credits based on book-and-claim RNG accounting could create a strong incentive for this pathway with potentially significant trade-offs for the deployment of HDV charging infrastructure and LCFS support of in-state GHG reductions.

Key concerns

Under the current proposal, LCFS credit generation for book-and-claim RNG use in linear generators could lead to this pathway being more financially favorable than using grid-supplied renewable electricity through 2035. The share of LCFS funding going to out-of-state livestock operations is already sizeable; this proposal would increase it. Additionally, it is unclear how the current proposal advances the state's goals of enabling long-term deployment of zero-emission trucks. The proposal incentivizes linear generator operators to continue to use fossil natural gas while claiming RNG attributes. When this RNG is produced outside of California, it does not contribute to achieving statewide emissions reductions goals.

Importantly, stimulus of linear generator deployment may also re-shape the direction of utility regulatory policy which until now has oriented towards proactive planning and investment in zones of high freight activity. Deployment of a fleet of linear generators beyond what CARB projects could limit the scale of grid-connected charging infrastructure reinforced by a de-facto policy preference for non-grid power. The Public Utilities Commission is developing proposals to support proactive investments to enable faster and larger connections to a grid powered increasingly by renewable electrons.[1] But CARB's incentives for non-grid power

[1] See California Public Utilities Commission proposed resolution E-5414 to implement scenario planning in the distribution process to better meet near-term customer needs and long-term growth. Available online at

generation would undermine this direction. The Public Advocates' Office of the Public Utilities Commission has concluded that higher rates of transportation electrification have the potential to put downward pressure on utility rates, but CARB's proposal would again limit grid connections that would deliver this benefit.[2] Proper alignment of CARB and CPUC objectives is missing in the proposal.

In light of these concerns, we suggest CARB take additional time to assess the impacts of its proposal. This can include consultation with the Public Utilities Commission, who is playing a key role in shaping state energy infrastructure investments. This consultation can ensure the proposal is complementary and supportive of their regulatory actions, while also ensuring LCFS investments fill a gap that ratepayer investments are unable to support. CARB's active participation in utility proceedings, including as a party to proceedings, can also ensure CARB actions are reflected in proceeding dockets and are taken into consideration in the utility regulatory process.

CARB is a pioneer at setting performance-based and technology-neutral solutions to meeting state air quality and climate objectives. Selecting a single technology for on-site distributed energy goes against this practice, leaving other distributed energy solutions unsupported. While we think support for near-term solutions is valid, the proposal can avoid the pitfalls of technology preference by taking a broader view of least-cost distributed energy resources that go beyond linear generators. A proper market assessment of all distributed energy solutions to identify those most deserving of support would serve to maximize the value of investments LCFS could make to ensure timely energization of commercial charging facilities and faster deployment of zero-emission commercial vehicles. Consultation with CPUC and CEC on this assessment can ensure LCFS investments are complementary and supportive of their regulatory objectives.

However, should CARB move forward with this proposal, safeguards would mitigate the risk of unintended market impacts. The immediate implementation of RNG deliverability requirements could ensure that

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https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M585/K850/585850473.PDF. Also see California Public Utilities Commission proposed resolution E-5413 to establish a uniform pending loads framework in the distribution planning process to identify geographic areas with high load growth and capacity constraints. Available online at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M585/K748/585748983.PDF

[2] https://www.publicadvocates.cpuc.ca.gov/press-room/reports-and-analyses/distribution-grid-electrification-model-2025

LCFS benefits are concentrated within California. Imposing deliverability requirements by 2030 or phasing out avoided methane crediting for pathways by 2030 could also help achieve the intended, near-term effects without broader LCFS and RNG market impacts over the next decade and beyond.

To address the concerns identified here and ensure near-term measures supporting HDV charging infrastructure are strategic and cost-effective, CARB could consider the following actions:

- Conduct a comprehensive assessment of technologically feasible, least-cost, and commercially available near-term solutions to energize commercial charging facilities;
- Take a technology-neutral approach to incentivizing near-term solutions, looking beyond a narrow focus on linear generators to include zero-emission solutions that may be a better use of public dollars and provide additional benefits to the electric grid.
- Conduct a proper assessment of net and cumulative air quality impacts under a scenario where LCFS credit prices do promote additional deployment of linear generators; include an assessment of impacts on disadvantaged communities; and consider scenarios where linear generators are concentrated in dense urban areas with limited grid capacity, high freight activity, and high density populations of disadvantaged communities.
- Consult with the Public Utilities Commission and the California Energy Commission on interim solutions CARB can support with LCFS revenue;
- Request formal party status and actively participate in Public Utility Commission Proceedings on Energization, High Distributed Energy Resources, and Transportation Electrification Planning
- Accelerate deliverability requirements for RNG pathways under the LCFS and phase out avoided methane crediting.

Below we outline our concerns in more detail.

The proposed changes could create preference for linear generator installation over zero emission solutions

A critical component of California's 2022 scoping plan is the use of zero-carbon electricity to power battery electric vehicles; the use of zero-CI electricity eliminates in-state greenhouse gas emissions covered by the AB32 inventory. Under the conditions analyzed by CARB in the ISOR

supplement, zero-CI electricity used for heavy-duty vehicle charging would generate $3.02 per diesel gallon equivalent of LCFS credits in 2026.

Linear generators, which rely on natural gas, are not considered in the scoping plan, and while use of these generators to charge electric vehicles would reduce in-state GHGs due to the greater efficiency of BEV powertrains, it would not eliminate GHGs entirely. Under the current LCFS program this benefit is already appropriately recognized; under the conditions analyzed by CARB, the linear generator pathway would receive $2.08 per diesel gallon equivalent (approximately $0.06/kWh) worth of LCFS credits —a significant incentive, but less than the zero-carbon electricity pathway.

The proposed changes would upend the current incentive structure, creating a strong preference for linear generators. Again, using CARB's assumptions, book-and-claim crediting would allow the linear generator pathway to generate $8.13 per diesel gallon equivalent of LCFS credits, a $5 per gallon premium over the zero-carbon electricity pathway.

Appendix F of the ISOR suggests that the proposed changes will not create an incentive for the use of linear generators nor the use of RNG credits by linear generator operators due to the higher cost of acquiring RNG relative to fossil natural gas ($45 per mmBTU vs $17.4 per mmBTU). However, this is true only under conditions of depressed LCFS credit prices. While CARB suggests that an LCFS credit price of $123 per MT CO2e would be required to incentivize a switch to RNG, our analysis suggests that RNG would be preferred so long as LCFS credit prices exceed $86.7 per MT (Table 1).[3] That price level is well within the projected credit price level of the LCFS in CARB's October 15-day package analysis in the scenario where 1 trigger of the auto-acceleration mechanism triggers; that scenario reaches a price of $112/tonne by 2026.[4]

[3] Under these conditions using the CARB ISOR supplement assumptions and the 2026 benchmark, RNG fuel cost would be 9.5 cents per MJ offset by 7.8 cents per MJ of LCFS credits for a net cost of 1.7 cents per MJ. For fossil natural gas, fuel costs would be 3.7 center per MJ offset by 2 cents per MJ of LCFS credits for a net cost of 1.7 cents per MJ.

[4] CARB, 2025. "Modeling Output Sheets from 15-day Package-- Uncertainty Scenario 1: Proposed Scenario with AAM trigger". https://ww2.arb.ca.gov/resources/documents/supplemental-20232024-lcfs-modeling-documentation

Table 1: Estimated LCFS Cost Impact on Natural Gas and RNG used for HDV Charging

Fuel	LCA Emissions (gCO_2e/MJ delivered electricity)	Fuel Price ($/MMbtu), Precombustion	Fuel cost, Post-Combustion ($/MMbtu of charging)	Fuel cost after LCFS Incentive ($/MMbtu of charging)		
				$67/tonne CO_2e	$86.7/tonne CO_2e	$123 tonne/$CO_2e$
Fossil Natural Gas	170 gCO_2e/MJ	$17.4	$38.7	$22.4	$17.6	$8.7
Biomethane	-500 gCO_2e/MJ	$45	$100	$36.3	$17.6	-$16.9
Price Difference ($/MMBTU)			-$61.3	-$13.9	$0	$25.6

Thus, it is very possible that book-and-claim RNG crediting incentivizes linear generators through 2035, which could in turn delay the widespread adoption of grid-connected HDV charging. Such a signal would serve to depress grid-side investments investor-owned utilities propose and would undermine recent attempts by the PUC to encourage proactive planning in advance of need.

The proposed changes could also contribute to the financial case for deployment of new natural gas infrastructure. For example, if by 2030 LCFS credit prices rise to $90 per MT and RNG procurement costs fall to $35 per mmBTU—a plausible scenario—linear generator operators would have negative fuel costs, generating $0.02 in revenue for every kWh of electricity supplied to vehicles. In contrast, under these same conditions, grid connected facilities would likely incur electricity costs on the order of $0.11 per kWh, even after the application of LCFS credits.[5]

The proposal is missing an assessment of air quality, public health, and environmental impacts, particularly impacts on disadvantaged communities. The proposal avoids this analysis by suggesting no increase in linear generator deployment. In light of the uncertainty in future credit values, it would be prudent to assess a range of credit values, including

[5] This assumes an average electricity cost of 26 cents per kWh taken from Southern California Edison's TOU EV-8 off-peak demand charge and offset by 15 cents per kWh of LCFS credits.

those that would facilitate growth of linear generator deployment, and the subsequent air quality implications of this growth.

Despite the lower emissions of linear generators relative to reciprocating engines, linear generators do not eliminate emissions, and there is likely to be a significant difference in the air quality impacts of widespread linear generator operation compared to grid-connected HDV charging through 2035. The likely co-location of linear generator deployment in urban industrial and residential zones with high freight activity and severe grid bottlenecks presents additional concerns. The proposal does not answer the extent to which expansive linear generator deployment would be cited in disadvantaged communities nor answer whether such deployment would have any impact on their air pollution burden.

It is necessary to consider the extent to which additional linear generators, both their number and their spatial allocation, make any meaningful difference in the cumulative and net exposure of residents living in non-confirming regions and in disadvantaged communities. It is also necessary to ensure linear generator stimulus would not compromise the state's ability to achieve national ambient air quality standards and the State Implementation Plan.

The proposal could result in further expansion of out-of-state avoided methane crediting

In its proposal, CARB cites Board Resolution 23-13, which directs staff to prioritize policy discussions related to SB 1383. Specifically, SB 1383 is intended to empower CARB to implement a strategy to reduce its short-lived climate pollutant emissions, including a target of reducing statewide methane emissions by 40% in 2030 relative to a 2013 baseline. However, expanding *book-and-claim* crediting through this provision does not support the goals of SB 1383. Though the Board explicitly directed CARB in its 2024 resolution to initiate a livestock methane regulation, this proposal instead expands the current lucrative subsidy. While the existing pathway for RNG-to-electricity incentivizes in-state farms and landfills to capture and combust methane, the proposed revision opens the system to allow out-of-state producers to generate sizeable credits with no tangible contribution towards California's methane targets.

Currently, apart from fuel cell generators, RNG based EV charging pathways require a direct connection between the RNG source and a generator feeding electricity into the California grid. This requirement is an

important safeguard. Due to the combined impact of avoided methane credits and the greater energy efficiency of electric vehicles, the RNG-EV pathway can generate significantly more LCFS credits than other fuel pathways. The existing RNG-to-electricity deliverability requirement ensures that these credits directly address California GHG emissions.

CARB's proposal would remove this safeguard. As we have discussed in prior comments,[6] book-and-claim avoided methane credits direct California's limited transportation decarbonization resources towards out-of-state livestock operations while not displacing in-state fossil fuel consumption. This is exacerbated by the lack of additionality to determine whether methane avoidance is attributable to the LCFS program. Expansion of book-and-claim to linear generators will create more opportunities for out-of-state RNG suppliers to receive LCFS support, and if linear generators became widely deployed at charging sites, the impact could be sizeable relative to the scale of the LCFS program.

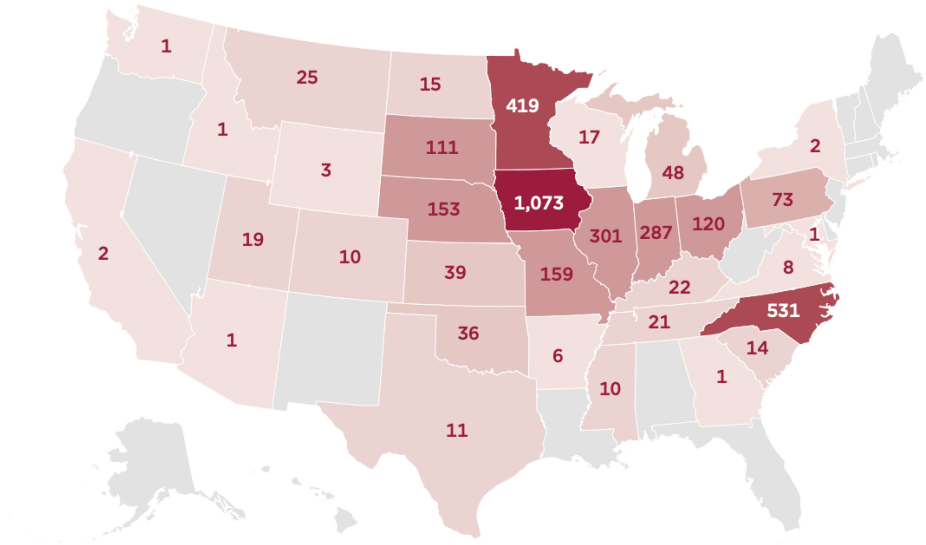
For example, we consider a recently approved swine manure CNG pathway for a farm located in Texas.[7] At a certified carbon intensity (CI) of -407 gCO_2e/MJ for CNG, this pathway would have an effective CI of -900 gCO2e/MJ after taking into account the efficiency losses for a linear generator. Factoring in the EER of a heavy-duty truck, this pathway would generate over $11 per diesel-gallon equivalents in LCFS credits, or approximately $90/MMbtu—more than sufficient to compensate for the cost differential between fossil and conventional natural gas. Based on the large size of this possible incentive, we recommend a more comprehensive analysis about the potential market implications of this change to the LCFS program. Highly-negative CI values for small quantities of book-and-claim fuel can meaningfully affect the LCFS's ability to support in-state deployment of renewable electricity and alternative fuels.

While avoided methane crediting associated with RNG is currently constrained by the volume of hydrogen, CNG and LNG consumed in vehicles, expanding book-and-claim to electricity greatly increases the potential contribution of these pathways to the LCFS program, as electric vehicle charging is projected to grow considerably over the next several

[6] https://theicct.org/international-council-on-clean-transportation-comments-on-the-proposed-low-carbon-fuel-standard-amendments-feb24/

[7] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0681_summary.pdf

decades. As detailed in a previous ICCT study,[8] there are hundreds of out-of-state dairy and thousands of swine farms that could take advantage of these incentives (See Figure 1 below).



Note: Grayed-out states have zero farms with at least 5,000 swine.

Figure 1: Distribution of swine operations per state with 5,000 or more swine

Should CARB choose to move forward with this proposal to support HDV charging site operators, there are several possible methods to safeguard against unintended consequences. For example, CARB could implement deliverability requirements to limit the contribution of out-of-state RNG producers, as is currently done for other LCFS pathways; CARB could therefore require that applicants demonstrate the physical flow in the gas grid by 2030. The economic incentive to use RNG and the outsized crediting could be limited by eliminating by phasing out avoided methane crediting, as is currently done for other LCFS RNG pathways. This could be implemented by limiting pathway applicants to a 5 or 10-year crediting period if they apply prior to 2030, or by phasing out avoided methane crediting for projects after 2030.

[8] https://theicct.org/publication/evaluating-the-policy-value-of-dairy-biomethane-derived-hydrogen-in-californias-lcfs-sept24/

There are other solutions to address the problem of charging site grid connection delays

As described in the ISOR supplement, the installation of linear generators at charging sites is already supported by the existing LCFS framework. Due to the challenge of establishing grid connections, these installations can help deliver immediate charging opportunities where existing natural gas infrastructure is available. However, because linear generators ultimately require a natural gas input, these installations are not compatible with a decarbonized economy.

In contrast, grid connected charging infrastructure aligns transport decarbonization with the state's strong commitments to zero carbon electricity generation. To directly accelerate the deployment of grid connected charging infrastructure, CARB could instead propose LCFS changes to support the interim solutions that utilities and their customers are already exploring to address grid constraints and accelerate energization timelines.

A selection of interim and permanent solutions to enable near-term site energization is captured below.[9]

Action by the customer	
Solution	**Description**
Accessing available capacity	There may be capacity on customer switchgear and electrical equipment that can enable limited charging capabilities in the near term.
Load management	To stay within capacity limitations, charging management systems can adjust charger power output based on the time of day or real-time grid conditions.
On-site generation	On-site generation such as solar panels or generators can help supply power for charging and reduce demand on the grid.
Energy storage	Energy storage can cover some of a site's energy needs and is ideally programmed to charge during off-peak periods. These can be configured so they are not connected to the electrical grid.

[9] Taken from Table 3 in Steimer, H. Minjares, R. and Allcock, C. (2025) How Seattle City Light can support private investment in charging infrastructure for medium- and heavy-duty vehicles. Available online at https://theicct.org/publication/how-seattle-city-light-can-support-private-investment-in-charging-infrastructure-for-mhdvs-sept25/

Action by the utility	
Solution	**Description**
Allow customer-supplied equipment	Customers could be allowed to supply and connect their own equipment, like transformers, to avoid potential equipment delays from the electric utility.
Feeder load balancing	Shifting loads temporarily or permanently to nearby feeders could open capacity on the feeder serving a charging site and avoid overloading a section of the distribution network while grid capacity improvements are performed.
Construction service delivery	Temporary construction service can be provided in 1–3 months and would allow a charging site to operate at limited capacity while permanent service is in development.
Mobile substations and temporary transformers	Mobile substations and transformers can be temporarily deployed to ensure priority customers can energize their facilities on time.
Dynamic line rating	Dynamic line-rating systems enable real-time adjustments of transmission carrying capacity and potentially defer the need for infrastructure investments.

Examples taken from California's experience to-date include utility-owned (front-of-the-meter) and customer-owned (behind-the-meter) interim solutions. A useful reference point for such examples is the set of summaries that investor-owned utilities have submitted in compliance with California Public Utilities Commission Decision (D.) 24-10-030 requesting bridging strategies and solutions.[10] Since this list is not comprehensive, we encourage CARB staff to work with California Energy Commission and California Public Utilities Commission staff to identify the full spectrum of technologically feasible, least cost, and commercially available interim solutions that CARB can support.

Flexible interconnections provide a useful example. In this arrangement, commercial and industrial customers agree to a schedule describing the power capacity available to their facility at predictable times that reflect existing grid distribution system constraints. And since it is not common for charging infrastructure customers to be operating at 100 percent utilization on day one, particularly those providing shared or public charging, utilities have been able to serve a growing number of customers with capacity limits or capacity schedules. This solution allows the customer to access a meaningful share of their power needs immediately, buying time for the utility to make the investments necessary to fulfill the customer's full needs.

[10] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M549/K805/549805932.PDF
https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M550/K147/550147940.PDF
https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M549/K805/549805853.PDF

As of December 2024, according to California investor-owned utilities, pilots of pre-agreed, static load control management systems exist for Pacific Gas and Electric (PG&E) and for Southern California Edison (SCE) through their Load Control Management System. Investor-owned utilities are meanwhile developing dynamic load control management with Distributed Energy Resource Management System (DERMS) to enable real-time load control.

Utilities are also experimenting with temporary mobile solutions. These include re-deployable mobile battery storage and mobile substations. In some cases, utilities can invest in stationary energy storage and stationary renewable generation sources, which provide long-term grid benefits through reduced need for grid buildout and improved resiliency after individual projects' conclusion. CARB investments through the Low Carbon Fuel Standard may already support utility investments in these solutions through expected credit revenue allocated through the Clean Fuel Rewards Program and its requirement that minimum allocations be made to equity-oriented projects such as those that investment in utility grid solutions.

Utilities can also support near-term investments by providing investment grade grid hosting capacity data. Commercial charging providers can avoid grid bottlenecks with higher quality, timely information that communicates where capacity already exists on the grid. But these customers face significant barriers to accessing this information, introducing significant investment risk in locations where the grid capacity is unknown. CARB staff could work with the PUC to encourage utilities to make available investment-grade information on grid hosting capacity that improves upon the less reliable data utilities current publish. CARB could further support utilities or third party companies with fleet advisory services designed to steer customers to grid locations where capacity already exists or where new capacity is due to come online.