



BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE

STATE OF CALIFORNIA

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**Order Instituting Rulemaking on California
Advanced Electric Rate Design.**

Rulemaking 26-04-009

(Filed April 09, 2026)

**CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION
OPENING COMMENTS ON ORDER INSTITUTING RULEMAKING
ON CALIFORNIA ADVANCED ELECTRIC RATE DESIGN**

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The California Large Energy Consumers Association ([CLECA](#))¹ submits these comments on the California Public Utilities Commission's (Commission) April 10, 2026, *Order Instituting Rulemaking On California Advanced Electric Rate Design* (Rulemaking)² pursuant to the directive and schedule set in the Rulemaking.

I. INTRODUCTION

CLECA's comments address a selected subset of the questions posed in the Rulemaking. Specifically, CLECA responds to Questions 3.3.1, 3.3.2, 3.3.6, and 3.3.7. CLECA does not address

¹ CLECA member companies produce goods essential for daily life, including critical infrastructure, oxygen for hospitals, and food distribution. CLECA members represent the steel, cement, industrial and medical gas, glass, beverage, minerals processing, cold storage, and pipeline transportation industries. Their aggregate electric demand is about 500 Megawatts, which is equivalent to the electricity consumption of approximately 470,000 average California households. CLECA members are large, high load factor and high voltage industrial electric customers in California for whom the price of electricity is essential to their competitiveness and for whom the reliability of electricity service is critically important. For both reasons, CLECA member companies have participated for decades in the Base Interruptible Program (BIP), providing reliability demand response to the grid in times of need. (For more information, please go to [CLECA.org](#)).

²CPUC, *Order Instituting Rulemaking On California Advanced Electric Rate Design*, R.26-04-009, (filed April 10, 2026) (Rulemaking), available at: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M604/K677/604677976.PDF>

the remaining questions at this time but reserves the right to respond to additional issues in the Reply Comments or subsequently in this proceeding.

II. COMMENTS

A. Question 3.3.1. Please provide comments on the list of preliminary issues. Are there any missing issues?

The Commission's preliminary issues for this proceeding are broad and appropriately encompass both residential and non-residential rate design matters.³ The scope and complexity of these issues underscore the importance of establishing a clear and deliberate procedural structure for addressing them.

Substantive comments on the preliminary issues are provided in response to Question 3.3.2, where CLECA addresses those issues in the context of proposed sequencing and prioritization for this proceeding. As discussed there, some issues will require careful, extended deliberation to ensure that policy determinations are coherent and internally consistent. At the same time, certain issues are more narrowly scoped and subject to statutory direction and are appropriate for more expedited consideration.

In addition to the identified issues, CLECA recommends adding a new scoped issue: whether rate design should explicitly consider the retention and expansion of energy-intensive, trade-exposed (EITE) customers as a policy objective, consistent with the state's interest in preventing emissions leakage.

³ Rulemaking, Section 3.1. at 11-13.

B. Question 3.3.2. Please provide comments on the schedule. Should this proceeding initially focus on only a portion of the preliminary issues? If so, which issues should be addressed first and why?

The Commission should structure this proceeding to address the identified issues in distinct tracks that reflect the differing scope, complexity, and statutory posture of the issues. A single track to address all issues would risk delaying matters that are time-sensitive and subject to clear statutory requirements, while also compressing more complex issues that require more time for careful and deliberate consideration.

Instead, the Commission should:

- (1) address Issue 3.1.I, concerning the implementation of AB 2109, on a standalone, expedited track;
- (2) defer Issues 3.1.b and 3.1.c, which implicate broader cost allocation and rate design reforms typically addressed in General Rate Case (GRC) Phase 2 proceedings, to a later track; and
- (3) address the remaining issues in an intermediate, general track.

This structure would allow each set of issues to be considered in a manner proportionate to its complexity and urgency, while promoting an efficient and coherent proceeding.

1. Track 1 (Expedited): AB 2109 Implementation

Implementation of Assembly Bill (AB) 2109 should be addressed first on a separate, expedited track. AB 2109 was passed in 2024 and requires the Commission to implement an exemption from nonbypassable or departing load charges for certain industrial process heat recovery technology, subject to narrow implementation details, including a statewide cap.⁴

⁴ AB 2109 (Carrillo), Stats. 2024, ch. 700; Rulemaking at 2, 13.

The statutory mandate is clear and straightforward in its core requirement; what remains is for the Commission to establish the cap and any additional prescribed requirements contemplated by the statute. This is a discrete, bounded implementation task that does not depend on the resolution of the broader rate design and marginal cost issues in this proceeding and will likely involve a limited subset of interested parties.

Expedited implementation is important because industrial customers considering investments in process heat recovery technology require regulatory certainty regarding the availability and implementation of the policy before making significant capital commitments. As noted by Assemblymember Juan Carrillo in his April 10, 2025, letter to President John Reynolds, the delay in implementation is already impeding investment and undermining the intended policy benefits of the statute.⁵ As Assemblymember Carrillo urges, the Commission should employ the most expeditious process necessary to implement AB 2109 and avoid unnecessarily deferring the issue within a broader rulemaking, which would needlessly delay implementation and be counter to the clear policy goals of this legislation.⁶

CLECA recommends that the Commission establish a dedicated schedule for AB 2109 implementation, including a targeted staff proposal or workshop, with the goal of issuing an expedited decision on this issue narrow in advance of this Rulemaking's broader rate design determinations.

⁵ Letter from Assemblymember Juan Carrillo to President John Reynolds, re: Request to Initiate Regulatory Proceedings for AB 2109, dated April 10, 2025.

⁶ *Id.*

2. Track 2 (Deferred): Marginal Cost Methodology and Revenue Allocation

The Commission should exercise caution with respect to issues 3.1.b and 3.1.c, which concern cost-of-service accuracy and marginal cost methodology reform. These issues should be addressed in a later, more deliberate phase of the proceeding, with sufficient time to examine the complexity of the underlying ratemaking questions.

These issues are central to the utilities' GRC Phase 2 processes, which have a well-developed procedural framework, involve extensive evidentiary records, and are frequently resolved through Commission-approved settlements. Such settlements are reached through multi-party negotiation processes and reflect balanced outcomes that account for competing customer interests, utility-specific circumstances, and practical implementation considerations. Disrupting this process through broad, generic directives risks unintended consequences.

Examination of whether marginal cost methodologies and rate structures can be improved is reasonable. However, the Commission should not resolve these issues through this proceeding on a compressed timeline. Any changes should only be prospective for future GRC Phase 2 proceedings.

The current GRC Phase 2 cycle reinforces this point. SCE's 2025 GRC Phase 2 (A.24-03-019)⁷ was resolved through a multi-party settlement, which the Commission recently approved

⁷ SCE, *Application of Southern California Edison Company (U 338-E) for Authority to Change Electric Rates*, A.24-03-019 (SCE 2025 GCR Phase 2) (filed Mar. 2024): <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M528/K409/528409332.PDF>

in a final decision.⁸ PG&E's 2023 GRC Phase 2 (A.24-09-014) is also proceeding on its own schedule and is likely to conclude before any substantive decision issues in this rulemaking.⁹

These large utilities will have recently completed or will be completing a full GRC Phase 2 cycle before this proceeding reaches the issues related to marginal cost and revenue allocation; accordingly, there is no procedural urgency to address these topics on a compressed timeline.

To the extent the Commission examines marginal cost methodology in this proceeding, modifications should be structured as principles or guardrails that guide, rather than replace, utility-specific GRC Phase 2 proceedings. For example, the Commission could address whether publicly available unit marginal cost data should be required as an input to other proceedings, such as dynamic rate design, without dictating specific methodological outcomes.

3. Track 3 (General): General Rate Design, Large Load, Data Center, and Dynamic Rate Issues

The remaining issues identified in Section 3.1 should be addressed through a general track that is broad enough to capture the principal rate design issues in a coordinated manner. Grouping these issues will allow the Commission to effectively consider related rate design questions while avoiding unnecessary delay on issues that are already affecting customer investment, interconnection, and electrification decisions.

⁸ CPUC, *Decision Approving Settlement Agreement*, A.24-03-019, D.26-04-033 (Apr. 2026): <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M606/K032/606032513.PDF>

⁹ PG&E, *Application of Pacific Gas and Electric Company (U 39 E) to Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design*, A.24-09-014 (PG&E 2023 GRC Phase 2) (filed Sept. 30, 2024): <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M541/K493/541493803.PDF>.

Within this general track, the Commission should include as a new issue whether rate design should explicitly account for the retention and expansion of EITE customers as a policy objective.

When rate design decisions render California electricity costs uncompetitive, production shifts to jurisdictions with less stringent environmental requirements, increasing global emissions rather than reducing them. The Legislature has recognized this risk in the enactment of AB 1207 (Irwin), which explicitly requires state programs, such as Cap-and-Invest, to minimize emissions leakage.¹⁰

Accordingly, the Commission should carry forward the Legislature's demonstrated interest in preventing emissions leakage into this Rulemaking. Rate design decisions in this proceeding, including cost allocation, nonbypassable charges, and rate signals for electrification, will directly affect whether EITE customers can remain competitive in California while committing to capital-intensive expansions that decarbonization requires.

Within this track, the data center and large-load customer rate design issues (3.1.j) warrant particular attention. First, the statutory timeline established by Senate Bill (SB) 57 requires a Commission assessment of data center cost impacts by January 1, 2027.¹¹ Second, there is an urgent need to develop rate design frameworks for new large loads that are already seeking interconnection. A distinct data center rate class may be reasonable, provided that any associated tariff requirements are narrowly tailored to the unique grid-operational impacts and stranded-cost risks presented by very large, new-technology data center loads. Such

¹⁰ AB 1207 (Irwin), Ch. 117, Statutes of 2025 at p. 8.

¹¹ Rulemaking at 8.

requirements should not be applied broadly to traditional large-load customers that do not present the same risk profile. CLECA addresses these concerns in greater detail in its response to Question 3.3.6 below.

The Commission should also address rate signals for industrial heat process producers, large commercial hydrogen production, and similarly positioned operations (3.1.k) in this track. Existing rate structures for large commercial and industrial customers contain extraneous costs that obscure the price signal in rates and do not provide accurate signals to encourage beneficial electrification or other decarbonization investments, or reward load flexibility. Improving these signals is critical, particularly for EITE customers, because their continued in-state operation and ability to decarbonize depend on electricity rates that are competitive with out of state competitors and that make electrification economically viable relative to fossil fuel alternatives.

Similarly, rate design adjustments to further support electrification and greenhouse gas reduction (3.1.f) should be addressed here. Consideration of these issues should not be limited solely to electrification but should encompass the full range of decarbonization pathways available to industrial customers, including carbon capture and sequestration and process heat recovery. Limiting the focus to electrification alone risks overlooking hard-to-electrify sectors where other decarbonization technologies may be more effective.

The Commission should also address whether additional rate design requirements are needed for dynamic rates (3.1.m) and establish that it must preserve customers' ability to participate in supply-side demand response programs, including the Base Interruptible Program

(BIP). Dynamic pricing and reliability-based demand response serve fundamentally different grid functions and should be treated as complementary, not mutually exclusive.¹²

Modernization of demand charges and nonbypassable charges, as identified in Issue 3.1.i, is closely connected to both the dynamic rate and large-load issues discussed above and should be considered in tandem to the extent it affects non-residential customers. Time-differentiated demand charges may provide more accurate price signals by better aligning customer costs with system conditions. In addition, the Commission should consider whether partial exemptions from nonbypassable charges may be appropriate for incremental loads undertaken specifically for decarbonization purposes, where those load additions would not otherwise occur and therefore would not shift costs to other ratepayers. CLECA addresses these concerns in greater detail in its response to Question 3.3.7.

Issue 3.1.d addresses whether additional elements of the utilities' authorized distribution revenue requirements, including the equal percentage of marginal cost (EPMC) scaled allocation of marginal customer costs, should be classified as fixed costs and recovered through fixed charges or demand charges. This is a significant cross-cutting issue that affects both residential and non-residential rate design. It should be addressed within the general track because its resolution will inform the rate structures applicable to large-load customers, dynamic rates, and demand charge design.

Similarly, Issue 3.1.n, which addresses whether the Commission should require different rate design adjustments for small and multi-jurisdictional utilities, is a procedural and structural

¹² CLECA, *Testimony of Sam Harper on Behalf of the California Large Energy Consumers Association*, A.24-06-014 et al., (Jan. 16, 2026) at 12-14.

issue that cuts across the topics in this track. It should therefore be addressed as part of the general track rather than deferred to a separate or later phase.

Rate reform issues that primarily impact residential customers could be addressed in parallel through a separate but concurrent track, including Base Services Charge adjustments (3.1.e), income verification processes (3.1.h), CARE program interactions (3.1.d to the extent it addresses residential rate design), baseline tier alternatives (3.1.g), and residential time-of-use rate alignment (3.1.a to the extent it addresses residential rates). These issues are largely focused on residential rate design and are already the subject of existing working group processes that should inform the procedural schedule.¹³ CLECA does not have substantive comments on these residential rate reform issues at this time, and therefore does not respond to Questions 3.3.3, 3.3.4, and 3.3.5. However, an organized procedural approach would allow residential issues to continue developing through a focused group of stakeholders without delaying consideration of broader rate design, non-residential, large-load, and dynamic rate issues.

4. Consultant Authorization

CLECA does not have comments on the consultant authorization Issue (3.1.o) at this time, but may address this issue in the Reply Comments. Accordingly, CLECA does not respond to Question 3.3.8 at this time.

¹³ Rulemaking at Attachment A (Process Working Group Report).

C. Question 3.3.6. What rate designs and tariff service agreement terms have been adopted in other states or regions for data center customers? Have other states or regions created a separate customer class for data center customers? Should these rates be applicable in California? If so, how?

Data center rate design and interconnection policy have recently become among the most actively debated utility regulatory issues across the United States. Multiple state commissions, regional transmission organizations, and reliability organizations are simultaneously developing frameworks to address the grid integration challenges and cost allocation questions posed by very large computational loads.

The California Legislature also recognized the urgency of this issue. Pending legislation would establish tailored rate structures and cost allocation requirements for large data center loads. The legislation reflects a policy objective to ensure that such customers bear the costs associated with their grid impacts while avoiding cost shifts to other ratepayers. For example, proposed legislation SB 978 would require the Commission to establish a distinct rate structure for data centers taking transmission-level service with an estimated peak demand of at least 75 megawatts (MWs); prohibit cost shifts to other customers; and require such data centers to pay upfront costs for transmission or distribution infrastructure upgrades necessary to provide service.¹⁴ SB 978 and other pending legislation define “data center” in a targeted manner intended to avoid encompassing more traditional large-load stakeholders.¹⁵

As discussed below, a consistent theme across jurisdictions is that the most effective approaches are narrowly tailored to the unique characteristics of large, hyperscale data

¹⁴ SB 978 (Pérez), as amended Mar. 23, 2026, available at: https://leginfo.ca.gov/faces/billNavClient.xhtml?bill_id=202520260SB978

¹⁵ *Id.*; see also proposed Pub. Util. Code § 740.22(a)(1)(A) – (B).

centers, rather than applied broadly to all large-load customers. In this respect, the establishment of a distinct large computational load rate class may be appropriate. However, any such rate class should be carefully designed to be targeted and non-punitive. Policies should protect other ratepayers from stranded costs and address operational grid concerns, while recognizing that data center development can provide system benefits.

When properly integrated into the grid, prudent load growth from new data centers can contribute to lower average rates by increasing the kilowatt-hour denominator over which fixed costs, such as wildfire-related costs, policy costs, and existing infrastructure investments, are recovered. Realizing this benefit, however, requires rate design that sends effective price signals and ensures that newly connected data center loads are responsible for the incremental costs they impose on the system; the rate design must also mitigate the risk that load departure or underperformance could result in stranded costs for other customers.

Experience from other jurisdictions provides useful reference points. For example, the Public Utility Commission of Texas (PUCT) is developing a large-load interconnection framework that establishes thresholds at levels intended to capture only the largest hyperscale facilities.¹⁶ The PUCT's 75 MW threshold and 250 MW tiered framework for additional deposit and security requirements for the largest loads is meaningfully higher than PG&E's proposed Electric Rule 30, which, as proposed, would apply more broadly to any transmission-connected load.¹⁷

¹⁶ PUCT, Project No. 58481, Rulemaking To Implement Large Load Interconnection Standards Under PURA 37.0561, establishing a threshold of 75 megawatts with additional requirements at 250 MWs.

¹⁷ PG&E, *Application of Pacific Gas and Electric Company (U39E) for Approval of Electric Rule No. 30 for Transmission-Level Retail Electric Service*, Application 24-11-007, (filed November 21, 2024), available at: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M547/K155/547155949.PDF>

Similarly, the Public Utilities Commission of Ohio has approved a data center-specific tariff that applies based on customer type rather than a generic load threshold. Under that framework, new data center customers with loads exceeding 25 MW are subject to enhanced minimum demand charges, multi-year contract terms, exit fees, and collateral requirements. Those requirements, however, do not apply to non-data center large loads of comparable size.¹⁸

Technical considerations further support this differentiated treatment. Reliability organizations and system operators have identified specific grid risks associated with large computational loads, including power quality issues, rapid ramping behavior, voltage and frequency ride-through characteristics, and impacts on system protection stability. For example, North American Electric Reliability Corporation (NERC) has issued a Level 3 Alert identifying specific reliability concerns posed by computational loads; these concerns include power quality issues such as voltage distortion, flicker, and harmonics; rapid ramping behavior; voltage- and frequency-ride-through characteristics; sub-synchronous oscillation risks; persistent small load fluctuations; and impacts on short-circuit levels and protection coordination.¹⁹

California Independent System Operator (CAISO) has also identified these same categories of technical risk in its January 2026 Large Load Considerations Issue Paper. CAISO notes that it and participating transmission owners have established a working group to

¹⁸ PUCO, Opinion and Order: *Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers*, Case No. 24-508-EL-ATA, July 9, 2025.

¹⁹ NERC, Level 3 Alert: *Essential Action to Industry - Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control* (May 4, 2026) at 3-7, available at: <https://www.nerc.com/globalassets/programs/bpsa/alerts/level-3-computational-load-alert.pdf>

develop coordinated technical requirements for interconnecting data center loads to the CAISO-controlled grid.²⁰

Similarly, the Electric Reliability Council of Texas (ERCOT) has also developed specific voltage ride-through requirements for large computational loads, addressing the technical grid reliability concerns associated with such loads directly rather than through generic interconnection standards.²¹

While it is appropriate for the Commission to consider tariff requirements that address the specific risks presented by data centers, any tariff service agreement framework should be carefully tailored so that it does not sweep in traditional large-load customers that present materially different and lower-risk profiles. Industrial facilities, universities, hospitals, and other longstanding large-load customers generally have more conventional load characteristics, established operating histories, and more predictable usage patterns. As a result, they do not present the same degree of uncertainty or system risk.

This distinction is particularly critical for energy EITE industrial customers and loads associated with industrial decarbonization, such as electrification of process heat and carbon capture investments. These customers are essential to California's climate and economic objectives and often require affordable electricity and reasonable interconnection processes to support capital-intensive investments. Applying deposit and financial security requirements designed for hyperscale data center operators with substantially different operational

²⁰ CAISO, *Large Load Considerations Issue Paper* (Jan. 30, 2026) at 13-14, available at:

<https://www.caiso.com/documents/issue-paper-large-load-consideration-jan-20-2026.pdf>

²¹ ERCOT, *Large Electronic Load Ride-Through Requirements: NOGRR 282 and NPPR 1308* (February 24, 2026), available at: https://www.ercot.com/files/docs/2026/03/02/04_LEL-RT-Requirements_SPWG_Feb2026.pdf

characteristics and business models to traditional loads would discourage electrification and decarbonization investments this proceeding is intended to promote.

Therefore, while a distinct class or set of tariff provisions for data centers may be appropriate, such policies should be narrowly tailored to the unique operational and financial characteristics of those loads. The Commission should adopt a balanced approach that protects the ratepayers, maintains grid reliability, and supports beneficial load growth, while avoiding unintended consequences for traditional large-load customers and related decarbonization efforts.

D. Question 3.3.7. What rate designs have been adopted in other states or regions for other large load customers, including for industrial heat process producers and large commercial hydrogen generation, to support electrification, beneficial load growth and load flexibility? Should these rate designs be applicable in California? If so, how?

Rate design is a foundational driver of whether California can successfully achieve its industrial decarbonization goals while maintaining an in-state manufacturing base. California industrial electricity rates are materially higher than those in other regions,²² placing EITE industries at significant risk of contraction or relocation. Where production shifts out of state due to energy costs, emissions are not reduced, but are rather displaced, resulting in emissions leakage that undermines both environmental and economic policy objectives.

Accordingly, reducing the effective cost of electricity for EITE customers, while adhering to cost-causation principles, is a necessary component of any strategy to support electrification

²² Little Hoover Commission. *The High Cost of Electricity in California*. Report #290. Sacramento, CA: Milton Marks Commission on California State Government Organization and Economy. October 2025. Available at: <https://lhc.ca.gov/wp-content/uploads/LHC-Report-290-The-High-Cost-of-Electricity-in-California-Final-Draft-Prior-to-Publication-10.31.25.pdf>

and beneficial load growth and flexibility. Rate design must therefore strike a careful balance: it should enable economically viable electrification and load growth, providing meaningful price signals that support grid operation and efficiency, and ensure that costs are allocated in a manner consistent with cost causation.

Other-State Approaches: Wholesale Price Exposure and Cost-Reflective Signals

The most effective rate designs adopted in other regions for large industrial customers share a common feature: they provide meaningful exposure to wholesale market price signals and align cost recovery mechanisms with the operational realities of the grid.

In regions such as PJM, MISO, and ERCOT, large-load customers are often able to take service in a manner that exposes them, either directly or through contractual arrangements, to hourly or sub-hourly wholesale prices. In addition, key cost categories, including capacity, transmission, and ancillary services, are frequently allocated based on coincident peak demand or hourly load ratio shares. These structures create strong incentives for customers to align consumption with system conditions, particularly during periods when energy is abundant and marginal costs are low.

These types of price signals are critical for industrial electrification and for emerging large loads such as hydrogen production. When rates reflect hourly system conditions, customers can structure operations to take advantage of low-cost, high-renewable output periods. This improves the economics of industrial decarbonization investments and encourages load shifting that supports system reliability. It also increases consumption during periods when renewable energy would otherwise be curtailed, thereby improving renewable utilization and reducing overall system costs.

By contrast, flat or heavily averaged volumetric rates obscure the true marginal cost of electricity and can make otherwise beneficial electrification investments appear uneconomic. A rate structure that masks hourly variation effectively eliminates the economic incentive for load flexibility, undermining both grid efficiency and decarbonization outcomes.

Application to California: Expanding Dynamic Pricing and Market Exposure

California has partially achieved similar outcomes through its Direct Access program, which allows certain qualifying customers to obtain exposure to wholesale market prices. However, participation remains limited due to administrative caps. The Commission should enable broader Direct Access participation as one mechanism to improve price signal exposure for large industrial customers.

Further, a significant portion of large industrial load remains subject to rate structures that do not fully reflect real-time system conditions. Reform to distribution rate structures, including customers on Direct Access and served through Community Choice Aggregators, can further enhance price signal transparency and alignment with cost drivers.

More broadly, the Commission should also implement similar price signals through dynamic rate design. Dynamic rates, particularly when tied to day-ahead or real-time market conditions, provide many of the same benefits as direct wholesale exposure within the existing regulatory framework. CLECA supports the timely development and deployment of dynamic rate options for large commercial and industrial customers, including Southern California

Edison's Consolidated Dynamic Rate Application.²³ CLECA also supports the extension and expansion of PG&E's locational marginal price-based pilot to incorporate large industrial loads, including those customers that also provide supply-side demand response through programs like the BIP.²⁴

These efforts should be designed to incorporate large industrial loads, including those capable of providing supply-side demand response. Participation in dynamic rates and demand response programs should not be mutually exclusive, as maintaining compatibility between these mechanisms will maximize load flexibility and system benefits. CLECA has consistently advocated in R.25-09-004 and in prior demand response proceedings that customers on dynamic rates should be permitted to participate.²⁵ The value of load flexibility is maximized when customers can respond to price signals through both rate design and program participation.

Addressing Policy Cost Adders That Obscure Price Signals

A critical distinction between California and many other jurisdictions is the magnitude and structure of policy-related cost adders embedded in retail rates. Nonbypassable charges, Public Purpose Program (PPP) charges, and similar components are typically volumetric and do

²³ SCE, *Application of Southern California Edison Company (U 338-E) for Approval of Large Power Dynamic Pricing Rate* (A.24-06-014), (filed June 26, 2024), available at <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M534/K357/534357113.PDF>

²⁴ CPUC, *Decision to Expand System Reliability Pilots of Pacific Gas and Electric Company and Southern California Edison Company*, R.22-07-005, D.24-01-032 (Jan. 25, 2024), available at: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M524/K176/524176497.PDF>

²⁵ CLECA, *Opening Comments on ALJ Ruling Seeking Comments on Demand Response Staff Proposal on Bridge Year Funding and Modifying the Schedule for Bridge Year Funding Issue*, R.25-09-004, (April 30, 2026).

not vary by time of use. As a result, they dilute or mask otherwise meaningful price signals derived from energy and capacity costs.

The Legislature contemplates this very issue in SB 943 (Becker). The various charges and adders directly affect electrification costs. Even where underlying energy costs are low during certain hours, fixed volumetric adders can render total delivered prices uncompetitive with fossil fuel alternatives.²⁶ This makes it difficult for electrification technologies, particularly those designed to operate during off-peak periods, to achieve cost parity. SB 943 addresses this issue by authorizing the Commission to apply an adjustment factor limiting the nonbypassable charge ratio to no more than 25 percent of total volumetric charges for eligible industrial transition customers with new, separately metered load used to provide industrial process heat.²⁷

The Commission should evaluate whether certain policy-related charges, particularly those not directly associated with the delivery of electric service, can be exempted or reduced for incremental electrification and decarbonization load. The economic logic is straightforward: where load would not exist absent the proposed rate design, there is no cost shift to other ratepayers because the alternative is zero contribution. At the same time, incremental load growth expands the kilowatt-hour base over which fixed system costs are recovered, producing net benefits for the system.

Alternatively, the Commission should consider whether these charges can be time-differentiated so that they do not flatten otherwise meaningful dynamic price signals.

²⁶ SB 943 (Becker), as amended Mar. 23, 2026, § 1(a)(7).

²⁷ *Id.*; see also proposed Pub. Util. Code § 759(b).

Continued collaboration with the Legislature on reforming or relocating policy cost recovery outside of volumetric electric rates may also be warranted.

Recovery of Fixed Costs and Preservation of Cost-Causation Principles

Finally, while increased exposure to dynamic price signals is essential, rate design must remain grounded in cost-causation principles. Some system costs are fundamentally fixed and do not vary with time of use or customer behavior. These costs are appropriately recovered through demand charges or customer charges, rather than through volumetric energy rates.

The appropriate balance is a rate structure that: (1) recovers genuinely fixed costs through demand or customer charges that are reasonable in magnitude and tied to cost causation; (2) preserves meaningful volumetric and time-differentiated energy price signals; and (3) ensures that customers are not required to bear costs that are disconnected from their actual usage of the grid.

In sum, other jurisdictions demonstrate that effective rate design for large loads relies on strong, time-varying price signals and cost-reflective allocation of system costs. The Commission should adopt similar principles through expanded dynamic rates, broader access to wholesale price exposure, and reform of nonbypassable charge structures that currently obscure price signals. These changes, implemented in a manner consistent with cost-causation principles, will enable industrial electrification, support beneficial load growth, and enhance grid reliability, while also helping to retain and expand California's industrial base and avoid emissions leakage.

III. CONCLUSION

CLECA appreciates the opportunity to provide these comments and encourages the Commission to:

- Add rate design to support EITE customer retention and expansion as a scoped issue in this proceeding, consistent with the state's interest in preventing emissions leakage.
- Organize this proceeding in distinct tracks that reflect the differing urgency and complexity of the issues identified, beginning with expedited implementation of AB 2109.
- Ensure that any new rate class or tariff framework for large computational loads is not punitive and is narrowly targeted to the risks specific to data centers.
- Provide large industrial customers with meaningful voluntary exposure to wholesale market price signals, whether through dynamic rates or expanded direct access.
- Consider exemptions or time-differentiated treatment of policy-related cost adders for incremental load associated with beneficial electrification investments.

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