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Order Instituting Rulemaking on California Advanced Rate Design.	Rulemaking 26-04-009

THE PUBLIC ADVOCATES OFFICE OPENING COMMENTS ON THE ORDER INSTITUTING RULEMAKING ON CALIFORNIA ADVANCED RATE DESIGN

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I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Pursuant to Rule 6.2 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure, the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) submits these opening comments to the Commission's Order Instituting Rulemaking on California Advanced Electric Rate Design (OIR), Rulemaking (R.) 26-04-009, issued April 10, 2026.[1] In the OIR, the Commission seeks to "establish advanced electric rate design policies to update residential and non-residential rate structures and their underlying cost inputs" so rates more accurately reflect service costs, send price signals that support efficiency, and allocate costs equitably across all customers.[2] Further, the Commission also intends to address remaining issues from the Demand Flexibility Rulemaking, R.22-07-005.[3]

The Commission intends to accomplish the goals of the OIR by considering a number of significant rate design issues[4] across customer classes, and within a 24-month timeline.[5] In this regard, the Commission should:

- Adopt Cal Advocates' proposed additional scoping issues which focus on electric rate affordability and placing downward pressure on electric rates for all customers;
- Modify the proposed scope to exclude consideration of marginal cost methods, because it is duplicative of work currently performed in General Rate Case Phase 2 (GRC 2) proceedings;
- Adopt Cal Advocates' proposal to separate issues into separate tracks and phases and provide additional workshop opportunities for efficient record development of complex rate design issues; and

[1] Rulemaking (R.) 26-04-009, *Order Instituting Rulemaking on California Advanced Electric Rate Design* (OIR), April 10, 2026.

[2] OIR at 1.

[3] OIR at 1.

[4] OIR at 10.

[5] OIR at 14.

- Adopt Cal Advocates' Proposed Modifications to the Income Verification Working Group Report proposal.

II. DISCUSSION

A. Rulemaking Question 1: Please provide comments on the list of preliminary issues. Are there any missing issues?

1. The Commission should supplement the preliminary scope with additional issues that could put downward pressure on electric rates for all customers.

The Commission should adopt the following additional scoping topics and issues which focus on electric rate affordability and placing downward pressure on electric rates for all customers.

a) Proposed additional issues for the Large-Load Topic.[6]

In the OIR, the Commission is considering rate design changes for data center customers or other large-load customers (large-load customers)[7] to prevent stranded costs and/or cost-shifting to other customer classes.[8] However, preliminary scoped issue "j" does not fully consider this issue.[9] The Commission should expand the large-load rate design scope to fully consider methods to mitigate rate increases for all customers resulting from serving new large-load customers. Accordingly, the Commission should adopt these additional scoping issues:

- Whether it would be just and reasonable to authorize the creation of a separate new customer class for data center or other large-load customers.
- Whether the incremental cost to provide service to data center or large-load customers that connect to the grid may shift costs or increase future rates for other customers.

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[6] OIR at 12 (Preliminary Scoped Issue "j"). Note, also related to Question 6 of the OIR. OIR at 15.

[7] Use of the term "large-load customer" in these comments includes data center customers as a subset.

[8] OIR at 12.

[9] Preliminary scoped issue "j" states "Are one or more new rate tariffs needed for data center customers and/or other large-load customers to prevent stranded costs and/or cost-shifting? If so, what should be included in the new rate(s)?" OIR at 12.

- The structure and timing of including data center and large-load costs in rates, including the potential for phased cost recovery over time to smooth rate impacts.

Before discussing data center and large-load customer tariff changes, the OIR should first establish whether to treat these customers as a separate customer class or continue to include these customers in the same class with other large-load customers. To this end, stakeholders will need to examine the electricity usage profiles for these customers and compare them to the profiles of existing customers as part of the consideration to adopt a separate customer class. This information would allow the Commission to consider which rate signals to send these customers to incentivize usage behavior that reduces rates for all customers. At the same time, discussion of how to determine the additional cost to serve data center and other large-load customers would help inform the Commission's report to the legislature pursuant to Senate Bill 57 (SB 57).[10] The Commission's determination on whether to create a new customer class early on will also inform discussion of large-load rate design options in a later stage of this OIR (Cal Advocates' proposed Phase C Track 7), and could lead to a more concise scope of modeling options in the proposed E3 Tool.[11]

The Commission should use this OIR to evaluate whether serving large-load customers may increase future rates for other customers.[12] If significant new demand

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[10] The report pursuant to SB 57 requires the Commission to include an assessment of whether costs incurred from serving new data center load will impact other rates for other ratepayers through cost shifts. Further, the Commission must also include potential mitigations for identified cost shifts. OIR at 8.

[11] The E3 tool is a public spreadsheet tool which models rate and bill impacts based on hypothetical scenarios. OIR, Attachment B: *Public Tool and Consulting Services for Development and Assessment of Advanced Rate Design Proposal* at 1-3.

[12] See Application (A.) 24-11-007, *Assigned Commissioner's Scoping Memo and Ruling on Pacific Gas and Electric Company's Request to Implement a New Electric Rule 30 Tariff*, March 11, 2025, at 5 ("Topics included pending legislation, rate structures, resource adequacy, reliability, and incremental generation costs. This Scoping Memo will not consider these additional issues...Therefore, while relevant to energy planning in general, these broader policy issues must be addressed in other, more appropriate forums."). See also A.24-09-014, *Administrative Law Judge's Ruling Denying Motion to Amend the Scoping Memo to Include New Issues Related to Large-Load Customers*, September 9, 2025, at 3 ("…Cal Advocates' motion to expand the scope of this proceeding to include new rate schedules for large-load customers and associated issues is denied. Broad large-load customer issues would be more appropriately addressed in a rulemaking.").

from large-load customers materializes, other customers may see increased rates from a tighter generation supply market, and the need for system capacity upgrades. In addition, the timing and structure of large-load costs affect how revenue requirements to serve these loads are established over time. Decisions around the timing of cost recovery, such as whether existing customers should bear the carrying costs associated with serving data centers and large-load customers, should be evaluated with rate design options and their impact on ratepayers. Broadening the scope of this OIR to explicitly include future rate impacts from serving large-load customers will lead to more fruitful discussions on whether additional rate design mechanisms should be adopted in this OIR to reduce the risk of future rate increases for all customers.

b) Proposed additional issues for the Dynamic Rates Topic.[13]

In this OIR, the Commission is considering whether additional rate design requirements are needed for dynamic rates.[14] The Commission should expand the scope of this issue to consider a method to evaluate the benefits resulting from dynamic rates for participants and non-participants and whether implementing dynamic rates are cost-effective. To meet this objective, the Commission should adopt the following scoping issue:

- What should be the ongoing process for monitoring and evaluating Dynamic Rate design structures and cost-effectiveness?

[13] OIR at 13 (related to Preliminary Scoped Issue "m").

[14] OIR at 13 (Preliminary Scoping Issue "m").

The three large Investor-Owned Utilities (IOUs) are currently developing and implementing dynamic rates,[15], [16], [17] thus development of a standard evaluation process should occur in this OIR so interested parties can provide feedback on the process. Expanding the scope to monitor and evaluate the benefits from dynamic rates would provide the groundwork for future proceedings. These future proceedings could examine whether dynamic rates should be the default rate for particular customer segments or whether additional modifications are needed to increase any benefits from dynamic rates.

c) Proposed additional issues for the Residential Rate Design Topic.[18]

The preliminary scope of the OIR considers whether baseline tier alternatives should be adopted. To fully consider this issue, the Commission should expand preliminary scoping issue "g"[19] to also consider modifications to the current baseline tiers that may increase benefits for residential customers. For example, The Utility Reform Network (TURN) proposed its own method to increase baseline allowances in Southern California Edison Company (SCE)'s GRC 2 proceeding[20] and the Commission identified a Rulemaking, such as this OIR, as the appropriate venue to address the proposal.[21] Similarly, TURN has raised proposals related to baseline allowances in Pacific Gas and Electric Company (PG&E)'s[22] current GRC 2 applications. By expanding the scope to

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[15] A.24-06-014 and A.24-12-008, *(1) Application for Approval of Large Power Dynamic Pricing Rate and (2) Application for Approval of Marginal Cost-Based Dynamic Pricing Rates in Compliance with Decision 22-10-022 and Load Management Standards*, consolidated February 20, 2025.

[16] A.24-09-014, *Application of Pacific Gas and Electric Company to Revise its Electric Marginal Costs, Revenue Allocation, and Rate Design*, September 30, 2024.

[17] A.26-02-001, *Application of San Diego Gas & Electric Company (U 902 E) for Approval of Demand Flexibility Rates in Compliance with D.25-08-049*, February 2, 2026.

[18] OIR at 12 (related to Preliminary Scoped Issue "g").

[19] OIR at 12 (related to Preliminary Scoped Issue "g").

[20] A. 24-03-019, *Prepared Testimony of Jennier Dowdell Addressing Select Revenue Allocation and Rate Design Issues* (TURN-01), January 8, 2025 at 2, lines 1-2.

[21] D.26-04-033, *Decision Regarding Southern California Edison Company's Application to Establish Marginal Costs, Allocate Revenues and Design Rates*, at 66

[22] A. 24-09-014, *Prepared Testimony of Sylvie Ashford Addressing Pacific Gas and Electric Company*

include the evaluation of baseline allowance modifications, the OIR should evaluate whether baseline allowance changes lower bills for certain customers, and how much baseline allowance levels impact residential bill volatility.[23] The proposed modification (underlined) to preliminary scoping issue "g" is:

- Should the Commission approve alternatives to baseline tiers or update baseline methodologies in time-of-use rates in order to improve customer understanding, improve vulnerable customer protections in hot climate zones, and support electrification? If so, how?

d) Proposed additional issue to increase transparency in the IOUs' marginal cost proposals in GRC 2s.[24]

As discussed below, the Commission should not include in the scope evaluation of marginal cost methods and whether current rates reflect cost-of-service in this OIR because they are duplicative of consideration performed in GRC 2 applications.[25] However, the Commission should use this OIR to increase the transparency of marginal cost proposals in GRC 2 applications by providing guidance on appropriate software. In GRC 2 applications, utilities are currently able to support their marginal cost proposals by performing calculations with any software of their choosing, including proprietary software, expensive software, and software that requires specific technical skill to

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2023 General Rate Case Phase II Application: Revenue Allocation and Rate Design (TURN-03), March 9, 2026 at 2, lines 5-9.

[23] The impact of changing baseline allowances and seasons on customer bill amounts and bill volatility was specifically considered in PG&E's 2017 GRC 2 (A.16-06-013), directed by the November 17, 2017, *Assigned Commissioner's Ruling Seeking Additional Information and Comment as it Relates to Electric Baselines, and Directing Pacific Gas and Electric Company to Supplement Schedule E-DMD and Schedule A-1 DMD*.

[24] OIR at 11-12 (related to Preliminary Scoped Issues "a" "f" and "i").

[25] See section II.A.2 of these Opening Comments.

calculate results (such as coding in a particular programming language).[26], [27], [28] This broad latitude reduces the ability of parties with limited financial or technological resources to evaluate the detailed calculations and assumptions in a utility's marginal cost proposals. Further, parties are often unaware of the particular software used until a utility either files their GRC 2 application or responds to a data request asking for workpapers supporting a particular proposal. This broad latitude allows the utility to continually "move the goal post" for parties in GRC 2 proceedings to evaluate and propose modifications to the utility's proposal. The Commission should use this OIR to set standard software requirements, so that the marginal cost and revenue allocation calculations are readily accessible to both parties and the Commission to evaluate. To meet this objective, the Commission should adopt the following scoping issue:

- Whether IOUs should be required to submit marginal cost, revenue allocation, and rate design workpapers using readily

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[26] For example, in PG&E's 2020 GRC 2 (A.19-11-019), Cal Advocates was required to use both "Statistical Analysis Software" (SAS) and "R" software packages, which each have their own programming languages, to validate PG&E's peak capacity allocation factor (PCAF) and final line transformer (FLT) proposals. Further, Cal Advocates review was limited to evaluating samples of PG&E's data set to ensure PG&E's computer code performed as intended. Cal Advocates uncovered numerous coding errors and inconsistencies in PG&E's computer code which took 6 months to request input data, run the computer code, and identify and correct errors. A.19-11-019, *The Public Advocates' Office Prepared Testimony On Pacific Gas & Electric Company's 2020 General Rate Case Phase 2*, October 23, 2020, Chapter 4: Distribution Peak Capacity Allocation Factors at 4-5 to 4-8.

[27] In SDG&E's 2024 GRC 2 (A.23-01-008), Cal Advocates identified anomalous results in SDG&E's marginal energy cost proposal, which are presumed to stem from SDG&E using an outdated version of the software. Identifying the cause of the anomalous results took a considerable amount of time replicating SDG&E's results using multiple versions of Plexos software. More importantly, Plexos requires a significant amount of technical skill, and the license fee is sufficiently expensive to likely exceed the financial resources of parties, thus inhibiting their ability to evaluate proposals or make their own proposals. A.23-01-008, *The Public Advocates' Office Prepared Testimony on Marginal Energy Costs in San Diego Gas & Electric Company's 2024 General Rate Case Phase 2*, December 8, 2023, at 3-8 to 3-11.

[28] In PG&E's current 2024 GRC 2 (A.24-09-014), PG&E modeled its proposed marginal energy costs using a proprietary software, that require knowledge of MATLAB coding, and oversight by PG&E's modeling group to fully evaluate PG&E's proposal. During Cal Advocates' review of PG&E's proposal, extensive errors in PG&E's computer code were found, and errata had to be filed which significantly added to the delay of the ongoing proceeding. Similar errors could have more readily been detected by parties if PG&E used a more accessible model to develop its proposal and would have reduced the timeline of this delayed proceeding. A.24-09-014, *The Public Advocates Office's Errata to Prepared Testimony on Marginal Energy Costs in Pacific Gas & Electric Company's 2023 General Rate Cas Phase 2*, February 6, 2026, at 1-10 to 1-24.

available software (i.e. Excel) instead of broadly inaccessible software models in General Rate Case Phase 2s.

2. The Commission should exclude consideration of marginal cost methods and whether current rates reflect cost-causation.

The Commission should modify the proposed scope to exclude consideration of marginal cost methods. This issue is duplicative of work currently performed in General Rate Case Phase 2 (GRC 2) applications.[29] Its exclusion will also allow parties to spend more time considering the other issues in this proceeding that impact rate design for all electric utilities. Specifically, the Commission should exclude development and analysis of improved marginal cost assessment methodologies for rate design for all customer classes from the proposed E3 Tool's scope and budget.[30, 31] Additionally, the following preliminary scoped issues should be excluded from consideration:

- Do existing residential and non-residential rates accurately reflect cost-of-service? If not, how should they be amended?[32]; and
- How should marginal cost inputs and methodologies be modified to better reflect the costs of providing service?[33]

The phrasing of these scoping issues does not account for the Commission's need to balance a number of goals when developing rates and not simply design rates based only on reflecting a customer's cost-of-service. For example, rates can incentivize public

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[29] "Second, the Commission moved electric rate design issues to a newly created Phase 2 proceeding; in subsequent decisions the Commission moved the related issues of marginal costs and cost allocation to Phase 2 as well." D.20-01-002, *Decision Modifying the Commission's Rate Case Plan for Energy Utilities*, January 16, 2020, at 15.

[30] OIR at 13 (Preliminary Scoped Issue "o"). Note, whether the proposed E3 Tool scope and budget should be adopted is also considered in Question 8 of the OIR. OIR at 15.

[31] "This budget will also support development and analysis of improved marginal cost assessment methodologies for rate design for all customer classes." OIR at Attachment B (*Public Tool and Consulting Services for Development and Assessment of Advanced Rate Design Proposal*) at 2.

[32] OIR at 11("b").

[33] OIR at 11("c").

policy objectives such as electrification technology adoption[34] and meeting greenhouse gas reduction goals.[35] Additionally, customer protection mechanisms may be necessary to mitigate rate and bill change volatility, leading to gradual rate over an extended time frame.[36]

Additionally, the development of marginal costs and evaluation of whether rates reflect the cost-of-service are already considered in a utility's GRC 2 application which occurs approximately every four years. The electrical grid and its associated costs are rapidly changing and the GRC 2 applications appropriately allow parties the opportunity to raise new data and methods to inform the development of marginal cost proposals. This proceeding should not attempt to pre-determine inputs and methods that may not be appropriate by the time another GRC 2 application is submitted. Inclusion of these issues in this OIR is duplicative of ongoing GRC 2 proceedings, procedurally inefficient, and thus unnecessary.

Finally, this OIR is already scheduled to consider an extensive number of topics on an expedited timeline, and exclusion of these preliminary scoped items will allow parties to spend more time considering issues that are not included in ongoing proceedings.

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[34] Each of the large electric IOUs provide rate options structured to incentivize electrification technology adoption through lower bills. Residential electrification rate options include PG&E's E-ELEC, SCE's TOU-D-PRIME, and SDG&E's TOU-ELEC.

[35] For example, the Commission could adopt steep time-of-use rate differentials which would charge customers more than their cost-of-service during periods when renewable generation resources are not available. Further, the Commission previously adopted a Super-User Electric Surcharge with a steep tier differential with the intention "[t]o be effective, this signal must go beyond a mere indication that the customer has passed into a higher usage tier; the customer must be able to clearly tell that a portion of their usage was far in excess of the typical household usage and that conservation steps should be taken." D.15-07-001, *Decision on Residential Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company and Transition to Time-of-Use Rates*, at 124.

[36] For example, the Commission also adopted multi-year glidepaths in D.15-07-001 when consolidating residential tiered rates to a structure with two tiers plus a super-user electric surcharge and reducing the California Alternate Rates for Energy discount to the legislatively approved values. D.15-07-001 at 327 (Conclusion of Law 10), at 329 (Conclusion of Law 25).

B. Rulemaking Question 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?

1. The proceeding should be organized into three consecutive phases with concurrent tracks.[37]

Given the extensive number of issues and procedural timeline, the Commission should address the issues in phases (which can occur sequentially) and tracks (that can occur concurrently within a phase). This organization allows parties the ability to devote resources only to the phases and tracks aligned with their concerns. Cal Advocates' proposed schedule efficiently organizes the issues sequentially such that certain foundational issues are considered and decided first, prior to consideration of later issues dependent on the outcome of the foundational issues. The proposed phases indicate the priority in the procedural timeline where consideration should occur (i.e. Consideration of Phase A should occur earlier in the proceeding, and Consideration of Phase C should occur later in the proceeding). Each track within a phase indicates an overarching topic for consideration of related scoped issues, and consideration of the separate tracks can occur concurrently within the same phase.

Phase A of the proposed schedule includes a single track to consider the scope and budget of the E3 Tool in Q3 2026 that will support later proposed phases and tracks. The Commission should address issues regarding the E3 Tool first because the E3 Tool will be used throughout the proceeding to assist parties with recommendations and proposals. The Commission should also require E3 to hold an all-party workshop where E3 can present a detailed proposed scope and functionality of the E3 Tool prior to its development. This workshop will provide parties with an opportunity to ask questions, raise proposals for capabilities of the E3 Tool and suggest modifications prior to its completion. If the Commission waits until the E3 Tool is essentially complete to accept suggested functionality recommendations and party feedback, there may be insufficient

[37] See Appendix A: Proposed Process and Scope of Issues for a comprehensive breakdown of Cal Advocates' recommended scoped issues and organization of workstreams.

time and funding to include the additional functionality and feedback later in the OIR.[38] After the workshop, E3 should submit a detailed summary that includes the potential scope for the E3 Tool, proposed functionality, and cost for implementation of each feature and then parties can submit comments and reply comment. The Commission can then issue a decision on this Phase to determine the final scope of the E3 Tool and budget.

The Commission should consider Phase B second in the procedural timeline, because the decision in Phase B may inform or impact consideration of issues in Phase C.[39] This proposed Phase includes tracks focused on the residential Base Services Charge (BSC), customer classification for data centers or some other segment of large-load customers, and evaluation of dynamic rates. Track 2 on fixed charge issues (focusing on the residential BSC and other shared fixed charge issues) should be addressed through a round of comments and reply comments leading to a decision. For Track 3, which covers new large-load customer classes and large-load cost impacts on other customers, the IOUs should host a workshop to discuss information from each IOU on their data center and large-load customer interconnection requests, customer characteristics, costs, etc. and the necessary issues to consider to evaluate potential cost shifts and development of a separate class. The workshop should lead to a round of comments leading to a decision. The workshop would also provide an opportunity for interested parties to inform the SB 57 report the CPUC must submit to the legislature by January 1, 2027 on large-load cost of service impacts on other customer classes.[40] Finally, proposed Track 4 should consider the evaluation of dynamic rates, which can be addressed by a round of comments leading to a decision.

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[38] In R.22-07-005, the Commission requested recommended changes after the tool was built, and there was only a sufficient amount of resources to make minor changes. Given the aggressive 24-month time to consider issues that will have a long lasting impact on how customers are charged for electricity usage, it's imperative for a robust tool that will efficiently allow parties to evaluate and develop proposals.

[39] For example, the Phase B decision may inform rate design issues in Phase C Track 5 on Residential Rate Design Issues and rate options for data centers considered in Phase C Track 7 regarding large-load rate design issues.

[40] OIR at 8.

Proposed Phase C includes three tracks. Track 5 covers residential rate design and focuses on baseline quantity issues. Track 5 should have a workshop with presentations from the IOUs. These presentations should cover any previous analysis performed regarding the bill magnitude and bill volatility impacts from changing baseline quantities.[41] The workshop should lead to a round of comments leading to a decision. Track 6 should address General Rate Design (for both residential and non-residential), and because it would be informed by the E3 Tool approved in Phase A, Track 1, E3 should present its tools and results in a workshop. Then parties should discuss potential changes to rate design and their impacts in working group discussions and produce a working group report. The working group report would be used to develop a round of comments leading to a decision. Finally, for Track 7 on large-load rate design, a separate large-load rate design working group should also develop a working group report to inform a round of comments leading to a decision. Track 7's large-load rate design working group also provides an opportunity to allow for an evaluation of the decision in PG&E's Rule 30 application in relation to the discussions in this track.[42]

Track B and C would have separate tracks running concurrently so the Commission could issue one decision to address all issues in a track or multiple decisions as tracks conclude. Consideration of whether the Commission should require small multi-jurisdictional utilities (SMJUs) to follow the same requirements as the large IOUs should occur in each track as applicable.

2. The Commission should adopt Cal Advocates' proposed proceeding schedule.

Cal Advocates proposes the schedule shown below for this proceeding. This schedule efficiently organizes the proposed scoping issues within the OIR so they can be

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[41] The impact of changing baseline allowances and seasons on customer bill amounts and bill volatility was specifically considered in PG&E's 2017 GRC 2 (A.16-06-013), directed by the November 17, 2017, *Assigned Commissioner's Ruling Seeking Additional Information and Comment as it Relates to Electric Baselines, and Directing Pacific Gas and Electric Company to Supplement Schedule E-DMD and Schedule A-1 DMD*.

[42] A.24-11-007, *Application of Pacific Gas and Electric Company (U 39 E) for Approval of Electric Rule No. 30 for Transmission-Level Retail Electric Service*, November 21, 2024.

effectively considered within a 24-month timeframe. Further, this proposal provides additional workshop opportunities for efficient record development of complex rate design issues covered in the preliminary scope.

Event	Proposed Date
Opening Comments on the OIR	May 11, 2025
Reply Comments on the OIR	May 21, 2026
Prehearing Conference	Q2 2026
Scoping memo and Ruling	Within 60 Days of PHC
Phase A (E3 Tool and Budget)	Q3 2026
Phase A Workshop (Track: E3 Tool and Budget Party Feedback)	Q3 2026
Phase A Decision	Q3 2026
Phase B (Tracks: Residential BSC, Large-Load Customer Class and Cost Impacts, and Dynamic Flex Rate Evaluation)	Begin Q3 2026
Phase B Decision(s)	
Phase C (Residential Baseline Quantity Issues, General Rate Design Topics Shared by Residential and Non-Residential Customers, and Large-Load Rate Design)	Begin Q2 2027 depending on whether the tracks can begin, some may require a Decision in Phase B
Phase C Decision(s)	

C. Rulemaking Question 3: What changes or updates are needed to improve the income verification processes used for the Base Services Charge (formerly the income-graduated fixed charge), as adopted in D.24-05-028? Please refer to the Process Working Group Final Report, served to the R.22-07-005 Service List on January 15, 2026, and included as Attachment A to this OIR.

If the Commission adopts the near-term income verification process recommendations included in the Process Working Group Final Report,[43] the

[43] OIR, Attachment A: *Income Verification Process Working Group Final Report*, January 15, 2026 (Attachment A) at 49-75.

Commission should also adopt Cal Advocates' recommendations included in the Advocate Statement section of the same report.[44] The recommendations include the following two improvements to the Income Verification Working Group Report proposal:

- The Commission should require utilities to refresh income data and recategorize customer census tracts every three years instead of every five years;[45] and
- The Commission should implement Cal Advocates' proposed Adjusted Geographic method for customer income categorization.[46]

The Income Verification Working Group Report proposal recommends that the income data used to categorize customers into different income tiers should be refreshed every five years.[47] Cal Advocates supports a more frequent income data refresh cycle of three years in the near-term.[48] First, a three-year income data refresh cycle provides customers with more opportunities to familiarize themselves with the novel process of paying for electricity at a price based on their household income.[49] Second, a more frequent data refresh cycle also provides customers with more outreach communications and opportunities to receive a lower BSC if their incomes decrease.[50] Less familiarity with this process may lead to inaccurate categorization and these customers being overcharged for their BSC.[51] Third, a three-year income data refresh cycle would more adequately account for changes in income.[52] The Income Verification Working Group Report proposal lacks accuracy regarding high-income customer categorization with only

[44] OIR, Attachment A at 105-110.

[45] OIR, Attachment A at 105.

[46] OIR, Attachment A at 105.

[47] OIR, Attachment A at 64.

[48] OIR, Attachment A at 105.

[49] OIR, Attachment A at 109.

[50] OIR, Attachment A at 105.

[51] OIR, Attachment A at 105.

[52] OIR, Attachment A at 105.

32.8% of high-income customers correctly categorized.[53] Refreshing the income data on a more frequent basis would improve the accuracy of high-income customer categorizations. Finally, refreshing the income data on a more frequent basis would increase the opportunities to evaluate and apply learnings to improve the implementation experience.[54]

The Commission should also implement Cal Advocates' proposed Adjusted Geographic method for customer income categorization to reduce the potential for revenue under-collections. The Income Verification Working Group Report proposal results in approximately 2.8 million high-income customers receiving a reduced BSC for which they do not qualify.[55] This means that there will be under-collections from high-income customers that will then be recovered from all customers, reducing the benefit of the BSC. This occurs because census tracts are economically diverse and include residences with a wide range of household income.[56] Thus, categorizing all customers based on the median income for the census tract will result in categorization errors. Further, these miscategorized high-income customers have no incentive to correct their inaccurate income categorization because the correction would result in a higher BSC.[57]

Cal Advocates' Adjusted Geographic method corrects these deficiencies by recategorizing a select number of moderate-income census tracts as high-income, which requires a negligible amount of extra work and cost.[58] Estimates show this method also accurately categorizes a higher percentage of customers than the Income Verification Working Group Report proposal.[59] Customers would still have the ability to verify their income to receive a moderate-income BSC instead of the high-income BSC. In addition,

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[53] OIR, Attachment A, Table 8-1 at 53.

[54] OIR, Attachment A at 105.

[55] OIR, Attachment A, Table 8-1 at 53.

[56] OIR, Attachment A, Figure 6-1 at 32.

[57] OIR, Attachment A at 106.

[58] OIR, Attachment A at 106.

[59] OIR, Attachment A, Table 12-Cal Advocates-1 at 108.

the Adjusted Geographic method is extremely flexible, because the magnitude of benefits can be adjusted solely by choosing a different number of moderate-income census tracts reclassify as high-income.[60] This flexibility provides the Commission with the ability to balance the number of customers in each income tier and improve categorization accuracy at virtually no additional cost.[61] Furthermore, the Adjusted Geographic method would likely reduce the BSC for moderate-income customers by reducing the likelihood of revenue under-collections.[62]

If the Commission adopts the Income Verification Working Group Report proposal, the Commission should also adopt Cal Advocates' recommended modifications to improve upon the working group's proposal and correct its deficiencies.

D. Rulemaking Question 4: Are there any statutory interpretation issues of the Public Utilities Code that were not resolved in R.22-07-005 and should be considered in this proceeding regarding the Base Services Charge, reform of residential rates to better reflect cost causation, or regarding the interplay between the California Alternate Rates for Energy (CARE) program and the Base Services Charge?

Cal Advocates has no comments on this issue at this time but reserves the right to respond to this question in reply comments.

E. Rulemaking Question 5: AB 205 amended Pub. Util. Code Section 739.9(c) to eliminate the requirement that the Commission "require each electrical corporation to offer default rates to residential customers with at least two usage tiers." Is it consistent with Public Utilities Code for the Commission to consider adopting default time-of-use rates that do not include usage tiers?

Cal Advocates has no comments on this issue at this time but reserves the right to respond to this question in reply comments.

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[60] OIR, Attachment A at 107.

[61] OIR, Attachment A at 109.

[62] OIR, Attachment A at 109.

F. Rulemaking Question 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?

Attachment A to these comments contains examples of rate design tariff service agreement terms that have been adopted in other states or regions for data center customers.[63] Some examples include a separate data center or large-load customer class, minimum demand charges, minimum service lengths, agreement for the customer to bring their own generation, minimum generation capacity contracts, mandatory emergency load curtailment, and requiring these customers to pay increased rates to pay for access to renewable generation sources.[64]

Whether these types of rates should be applicable in California should be discussed later in the proceeding, such as in Phase B Track 3 (Separate Large-Load Customer Class and Cost Impacts on Other Customers) and Phase C Track 7 (Large-Load Rate Design).

G. Rulemaking Question 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?

Attachment A of these comments contains examples of rate designs promoting electrification, beneficial load growth, and load flexibility for industrial customers.[65] Whether these types of rates should be applicable in California should be discussed later in the proceeding, such as in Phase C Track 7 (Large-Load Rate Design).

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[63] Attachment A: Data Center and Large Load Rate Design and Tariff Examples, May 2026.

[64] See Attachment A at 2-22.

[65] See Attachment A at 22-23.

H. Rulemaking Question 8: Should the Commission authorize the Proposal for Consultant Contract provided in Attachment B? Should any amendments to the proposal be made?

Yes, the Commission should authorize the Proposal for Consultant Contract with modifications. The Commission should remove the following sentence from the "Proposed Scope and Budget" section of the Proposal: "This budget will also support development and analysis of improved marginal cost assessment methodologies for rate design for all customer classes."[66] This aspect of the proposed scope and budget is duplicative of work currently performed in GRC 2 proceedings. Furthermore, exclusion of this issue will allow parties to focus on the numerous and substantial issues in this proceeding that impact rate design for all electric utilities.

Finally, as discussed above, the Commission should also provide an explicit scope of work for the E3 Tool for parties to comment on, before the development of the tool, so party recommendations can be included in the front-end of development.[67]

III. CONCLUSION

Cal Advocates appreciates the opportunity to comment on and participate in this OIR that will directly impact how customers are charged for electricity use. The Commission should adopt Cal Advocates' recommended modifications to the preliminary scope and schedule to ensure these substantial issues are fully evaluated and considered.

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[66] OIR, Attachment B: *Public Tool and Consulting Services for Development and Assessment of Advanced Rate Design Proposal* at 2.

[67] See section II.B.1. of these opening comments.

Respectfully submitted,

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May 11, 2026

Appendix A:
Process and Scope of Issues

Process and Scope of Issues for Phase A:

Track 1: E3 Tool (Approval of Scope and Funding)
Scoped Issue(s): • Preliminary Scoped Issue "o": Should the Commission authorize funding for third-party consultant services to support the development of rate design and bill impact analysis tools and to support Energy Division staff analysis of rate design issues in this proceeding?
Process: Workshop and round of comments leading to Decision.

Process and Scope of Issues for Phase B Tracks which can run concurrently.

Track 2: Fixed Charge and Costs (residential Base Services Charge and shared fixed charge issues)	Track 3: Separate Large-Load Customer Class and Cost Impacts on Other Customers	Track 4: Dynamic Rate Evaluation
Scoped Issue(s): • Preliminary Scoped Issue "e": Should the Commission adjust residential Base Services Charges (also known as income-graduated fixed charges) to recover certain authorized fixed utility costs in accordance with Pub. Util. Code Section 739.9, adopted electric rate design principles, and demand flexibility design principles? If so, how? • Preliminary Scoped Issue "d": Should further elements of a utility's authorized distribution revenue requirement, including the equal percentage of marginal cost (EPMC) scaled allocation of marginal customer costs and wildfire-related costs, be classified as fixed costs? What rate designs, such as fixed charges or demand charges, should the Commission consider for the recovery of these costs for both residential and non-residential customers? • Preliminary Scoped Issue "h": What changes or updates are needed to improve the income verification processes used for the Base Services Charge, as adopted in D.24-05-028? • Preliminary Scoped Issue "n": Should the Commission require different adjustments to rates and rate design methodologies for large electric investor-owned utilities and the small and multi-jurisdictional utilities in this proceeding? If so, how should the requirements differ for the small and multi-jurisdictional utilities?	Scoped Issue(s): • Proposed Scoping Issue: Whether it would be just and reasonable to authorize the creation of a separate new customer class for data center or other large-load customers? • Proposed Scoping Issue: Whether the incremental cost to provide service to data center or large-load customers that connect to the grid may shift cost or increase future rates for other customers? • Preliminary Scoped Issue "n": Should the Commission require different adjustments to rates and rate design methodologies for large electric investor-owned utilities and the small and multi-jurisdictional utilities in this proceeding? If so, how should the requirements differ for the small and multi-jurisdictional utilities?	Scoped Issue(s): • Proposed Scoping Issue: What should be the ongoing process for monitoring and evaluating Dynamic Rate design structures and cost effectiveness? • Preliminary Scoped Issue "m": Should the Commission provide any additional rate design requirements for dynamic rates? If so, which?
Process: Round of comments leading to Decision.	**Process: Workshop and round of comments leading to Decision. Workshop can inform SB 57 report.**	**Process: Round of comments leading to Decision.**

Process and Scope of Issues for Phase C Tracks which can run concurrently.

(Note: Certain track start dates may depend on activities in other tracks and decision issue dates in previous phases.)

Track 5: Residential Rate Design (baseline issues)	Track 6: General Rate Design (for both residential and non-residential)	Track 7: Large-Load Rate Design
Scoped Issue(s): • Proposed Modification to Preliminary Scoped Issue "g": Should the Commission approve alternatives to baseline tiers in time-of-use rates or update baseline methodologies in order to improve customer understanding, improve vulnerable customer protections in hot climate zones, and support electrification? If so, how? • Preliminary Scoped Issue "n": Should the Commission require different adjustments to rates and rate design methodologies for large electric investor-owned utilities and the small and multi-jurisdictional utilities in this proceeding? If so, how should the requirements differ for the small and multi-jurisdictional utilities?	Scoped Issue(s): • Preliminary Scoped Issue "a": Do existing residential and non-residential time-of-use rates align with current system load patterns and/or grid cost drivers? If not, how should they be amended for alignment? • Preliminary Scoped Issue "f": Should the Commission adjust electric rate designs to further support California's transition to electrification and the reduction of greenhouse gas emissions? If so, how? • Preliminary Scoped Issue "i": How should the Commission modernize demand charges and nonbypassable charges for consistency with the adopted electric rate design principles and demand flexibility design principles? • Proposed Scoping Issue: Whether IOUs should be required to submit marginal cost, revenue allocation, and rate design workpapers using readily available software (i.e. excel) instead of broadly inaccessible software models in General Rate Case Phase 2s? • Preliminary Scoped Issue "n": Should the Commission require different adjustments to rates and rate design methodologies for large electric investor-owned utilities and the small and multi-jurisdictional utilities in this proceeding? If so, how should the requirements	Scoped Issue(s): • Preliminary Scoped Issue "j": Are one or more new rate tariffs needed for data center customers and/or other large-load customers to prevent stranded costs and/or cost-shifting? If so, what should be included in the new rate(s)? • Preliminary Scoped Issue "k": Should the Commission improve rate signals for large-load customers, including for industrial heat process producers and large commercial hydrogen generation, to support electrification, beneficial load growth and load flexibility? If so, how? • Preliminary Scoped Issue "l": How should the Commission implement AB 2109 requirements to implement an exemption from nonbypassable or departing load charges for certain industrial customers that utilize process heat recovery technology, subject to a cap and prescribed requirements to be established by the Commission? • Preliminary Scoped Issue "n": Should the Commission require different adjustments to rates and rate design methodologies for large electric investor-owned utilities and the small and multi-jurisdictional utilities in this proceeding? If so, how should the requirements differ for the small and multi-jurisdictional utilities?

	differ for the small and multi-jurisdictional utilities?	
Process: Workshop and round of comments leading to Decision.	**Process: Workshop on E3 tool. Working group leading to report then a round of comments leading to Decision.**	**Process: Working group leading to report then a round of comments leading to Decision.**

ATTACHMENT A

Data Center/Large Load Rate Design and Tariff Examples
Advanced Electric Rate Design OIR
R.26-04-009
May 2026

I. INTRODUCTION

In its Order Instituting Rulemaking on California Advanced Electric Rate Design (R.26-04-009), the California Public Utilities Comision (CPUC or the Commission) requested parties to comment on the following questions related to large load customers:[1]

- 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?
- 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?

This paper provides examples of how public utilities commission (PUCs) and utilities in the United States and Canada have designed rates and tariff service agreements to achieve objectives related to the growth of large load customers.

II. SAFEGUARDS IN LARGE-LOAD RATE DESIGNS

A. Establishing Guidelines for Reviewing Large-Load Contracts

In service territories without specific data center or large-load tariffs, utilities and data center customers are negotiating their electricity service agreements through special contracts, subject to approval by their applicable PUC.

Examples:

- The Kentucky Public Service Commission: **established** guidelines for itself that required it must make several findings before approving a special contract. These findings include a) the special contract only includes discounts to customers when the utility has excess generation capacity, b) discounts are limited to five years and no more than half the duration of the contract, and c) the contract rate exceeds the utility's marginal costs to serve that customer and d) the

[1] Rulemaking (R.) 26-04-009, *Order Instituting Rulemaking on California Advanced Electric Rate Design* (OIR), April 10, 2026, at 15 (Questions 6 and 7 for Party Comment).

customer has to pay any utility's fixed costs associated with providing service to the customer.[2]

- NV Energy's Clean Transition Tariff **(approved)**: designed for existing, bundled, large-load customers to voluntarily source dedicated new clean energy resources from the utility. Under this tariff, large customers with an annual hourly load of 5 megawatt (MW) or more can execute an Energy Supply Agreement (ESA) with the utility. The Nevada PUC must review each ESA and determine whether it is in the public interest and if non-participating customers will experience increased costs or forego any benefits as a result.[3]

B. Creation of a New Data Center Rate Class

Some states have approved the creation of a new data center class to better account for revenues and costs associated with serving these customers.

Examples:

- Public Utilities Commission of Ohio (PUCO): in July 2025, PUCO **approved** AEP's creation of a new customer class for data centers with a monthly demand of 25 MW or more at a single location.[4] AEP argued that data centers' unique size, uncertainty about their energy use over the long-term, and

[2] Kentucky Public Service Commission, Order in the Matter of Electronic Tariff Filing of a Kentucky Power Company for Approval of a Special Contract with Ebon International, LLC Case no. 2022-00387, August 28, 2023, at 4-5, available at https://psc.ky.gov/pscscf/2022%20Cases/2022-00387/20230828_PSC_ORDER.pdf.

[3] Public Utilities Commission of Nevada (PUCN), *Re: Docket No. 24-05022 – Application of Nevada Power Company d/b/a NV Energy, filed under Advice Letter No. 547, to implement Clean Transition Tariff Schedule No. CTT to allow eligible customers to receive bundled electric service from new clean energy resources*, July 11, 2025, Schedule No. CTT Clean Transition Tariff, at PDF pages 4 and 6, available at https://puc-onbase.nv.gov/api/Document/AR1u41K1Yay0ARZ4djTD%C3%89dZof8NgEVlGZasxD%C3%890kammtZoyCH2mLGtUzJhvnTwG6%C3%81qmwaLh0x8JqN5hF6DgFnW0%3D/?OverlayMode=View.

[4] The Public Utilities Commission of Ohio (PUCO), Case No. 24-508-EL-ATA, *Opinion and Order*, July 9, 2025, at 14-23, 95, available at https://dis.puc.state.oh.us/DocumentRecord.aspx?DocID=badab793-e041-4173-9b6d-436e51f80e5c.

minimal employment opportunities make them different than other energy-intensive customers.[5]

- Virginia State Corporation Commission (VSCC) in 2025 **approved** a new GS-5 rate class for customers with a measured or contracted demand of 25 MW or greater and a measured or expected load factor of at least 75%.[6] The VSCC found that creating this new rate class of customers with similar cost causation and usage characteristics and will allow for more accurate allocation of costs.[7]
- The Public Utilities Commission of Oregon is **reviewing** a proposed new customer rate class by Portland General Electric (Docket UM 2377).[8] PGE proposed this new customer rate class in compliance with the newly signed Oregon House Bill 3546.[9] This bill directs the Oregon PUC to create a specific class of service for large energy use facilities that consume more than 20 MW of power that is "distinct from classifications of service for other commercial or industrial retail electricity customers and have its own tariff schedule."[10] This bill aims to correctly allocate the costs of serving these customers to the new class and prevent unwanted cost shifting.[11]

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[5] PUCO, Case No. 24-508-EL-ATA, *Direct Testimony of Matthew S. McKenzie On Behalf of Ohio Power Company, May 13, 2024*, at 7-9, available at https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A24E13B43247C00950.

[6] Virginia State Corporation Commission (VSCC), PUR-2025-00058, *Final Order*, November 25, 2025, at 23, available at https://www.scc.virginia.gov/docketsearch/DOCS/89g601!.PDF.

[7] Virginia State Corporation Commission, PUR-2025-00058, *Final Order*, at 10 and 23, available at https://www.scc.virginia.gov/docketsearch/DOCS/89g601!.PDF.

[8] Public Utility Commission of Oregon, UM 2377, Portland General Electric Opening Testimony, August 11, 2025, at 3, available at https://edocs.puc.state.or.us/efdocs/HTB/um2377htb338993027.pdf.

[9] Public Utility Commission of Oregon, UM 2377, Portland General Electric Opening Testimony, at 3, available at https://edocs.puc.state.or.us/efdocs/HTB/um2377htb338993027.pdf.

[10] Oregon State Legislature, House Bill (HB) 3546 (Marsh, 2025 Reg. Sess.). Relating to large energy use facilities; and declaring an emergency, also known as POWER Act, Section 2(2), at 1, available at https://olis.oregonlegislature.gov/liz/2025R1/Downloads/MeasureDocument/HB3546.

[11] Oregon State Legislature, House Bill (HB) 3546 (Marsh, 2025 Reg. Sess.). Relating to large energy use facilities; and declaring an emergency, at 1, available at https://olis.oregonlegislature.gov/liz/2025R1/Downloads/MeasureDocument/HB3546.

C. Creation of a New Data Center/Large Load Tariff

Some states have created new data center-explicit or large load tariffs applicable to data centers in the past few years, even if they did not create a new data center rate class. Examples:

- The Public Utilities Commission of Ohio **approved** AEP Ohio's creation of a new class and tariff (Schedule DCT) for data centers in July 2025.[12]
- The Arkansas Public Service Commission **approved** Arkansas Electric Cooperative Corporation (AECC)'s new Transmission Extension of Facilities Tariff (TEOF) in August 2025.[13] The TEOF requires power-intensive users (PIUs), defined as a retail customer with a demand exceeding 50 MW, to pay for new transmission upgrades and extensions, called a contribution in aid of construction (CIAC). These PIUs would pay to relevant member cooperatives, who then pass these funds to AECC.[14]

D. Contract Duration, Load Ramp Period, Minimum Charges, Exit Fees

To protect ratepayers from shouldering stranded asset costs, state PUCs have instituted minimum contract durations, ramp times, and exit fee requirements for data center and large loads in recent years.

Examples:

- Dominion Energy's GS-5 rate class **(approved)**: large load customers of 25 MW or more require a 14-year contract term, with a load ramp period not to exceed 4 years.[15] If the customer stops operation or defaults on the contract

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[12] PUCO, Case No. 24-508-EL-ATA, *Finding and Order*, July 23, 2025, at 2, available at https://dis.puc.state.oh.us/DocumentRecord.aspx?DocID=8d199170-7c95-482e-a524-9128c56ef36e; PUCO, American Electric Power, *Re: In the Matter of the Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers*, July 11, 2025, at 3-10, available at https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A25G11B21315A00184.

[13] Arkansas Public Service Commission (APSC), Docket No. 25-031-TF, Order No. 6, *Order*, August 26, 2025, at 3, available at https://apps.apsc.arkansas.gov/pdf/25/25-031-TF_14_1.pdf.

[14] APSC, Docket No. 25-031-TF, Order No. 6, *Order*, at 1, available at https://apps.apsc.arkansas.gov/pdf/25/25-031-TF_14_1.pdf.

[15] VSCC, Case no. PUR-2025-00058 *Final Order*, November 25, 2025, at 23-28, available at https://www.scc.virginia.gov/docketsearch/DOCS/89g601!.PDF.

agreement, the customer has to pay an exit fee along with minimum charges for the remaining contract duration, which can amount to 60% for generation, 85% for transmission, and 85% for distribution of contracted demand.[16] Reassignment of capacity is possible, which means if the customer chooses to exit early, the customer can reassign the contracted capacity to another customer agreeing to assume the capacity.[17] This option is covered in greater detail in #11 below.

- Kentucky Power's Tariff Industrial General Service **(approved)**: has a minimum 20-year contract term for all new loads of 150 MW or greater, which represents the higher end of the minimum contract term lengths across approved large load tariffs.[18] If there is a "permanent closure by the customer" after the first five years of the initial contract term, the customer may exit the contract by paying a one-time payment equal to five years minimum billing under the tariff.[19]
- Indiana Michigan Power's Industrial Power Tariff **(approved)**: has a minimum contract length of 12 years for customers at or over 70 MW individually or 150 MW in the aggregate.[20] The large load customer can take advantage of a load ramp period of no more than 5 years, after which the

[16] VSCC, Case no. PUR-2025-00058 *Final Order*, at 23-28, available at https://www.scc.virginia.gov/docketsearch/DOCS/89g601!.PDF.

[17] VSCC, Case no. PUR-2025-00058 *Final Order*, at 23-28, available at https://www.scc.virginia.gov/docketsearch/DOCS/89g601!.PDF.

[18] Kentucky Power Company, *Rates, Terms, and Conditions for Furnishing Electric Service,* "Tariff I.G.S. (Industrial General Service)," February 8, 2024, at PDF page 56, available at https://psc.ky.gov/tariffs/Electric/Kentucky%20Power%20Company/Tariff.pdf.

[19] Kentucky Power Company, *Rates, Terms, and Conditions for Furnishing Electric Service,* "Tariff I.G.S. (Industrial General Service)," at PDF page 56, available at https://psc.ky.gov/tariffs/Electric/Kentucky%20Power%20Company/Tariff.pdf.

[20] Note: Indiana and Michigan Power (I&M) originally proposed a 20-year contract term to "reasonably" recover its generation infrastructure investments and financial commitments related to serving large load. Amazon objected in interventor testimony, arguing that no other electric utility requires a 20-year term, such a term would incentivize I&M to over-invest in long-term commitments, and that contract durations should not be tied to the lifespan of the utility's generation/infrastructure investments because the utility has done so in the past. Indiana Michigan Power, "Tariff I.P. (Industrial Power)," February 19, 2026, at PDF page 88, available at https://www.indianamichiganpower.com/lib/docs/ratesandtariffs/Indiana/IM_IN_TB_20_04-30-2026.pdf.

minimum contract length would begin.[21] This tariff sets the monthly billing demand as no less than "the greater of (a) 80 percent of the Large Load Customer's contract capacity specified for the applicable time period of the Contract Term; or (b) 80 percent of the Large Load Customer's highest previously established Monthly Billing Demand during the past 11 months."[22] If the large load customer wishes to terminate its contract or reduce its contract capacity by more than 20% after the first five years of the contract term, it would have to give the utility at least 42 months of prior written notice and pay an exit fee.[23] The exit fee would be calculated as:

"[T]he nominal value of the remaining Minimum Charge for the terminated/reduced capacity in excess of the 20% allowed reduction for the first year of the Exit Fee Period; and for any remaining year of the Exit Fee Period, the Exit Fee shall be calculated in the same manner as the first year, minus the OSS/PJM Rider's (or the same cost addressed in another rider's) contribution to the Minimum Charge. The Exit Fee Period is defined as the Large Load Customer's remaining Initial Contract Term, or any agreed extension. The Exit Fee Period shall not be less than one year and shall not exceed five years."[24]

- Ameren Missouri's Large Load Customer Service Rate **(approved)**: for customers at or above 75 MW requires a minimum of 12 years after a 5 year optional load ramp period.[25] If the customer chooses to terminate the contract during the load ramp period, the customer would have to pay Ameren Missouri an Exit Fee equal to the nominal value of the applicable minimum monthly bill multiplied by the number of

[21] Indiana Michigan Power, "Tariff I.P. (Industrial Power)," at PDF page 88, available at https://www.indianamichiganpower.com/lib/docs/ratesandtariffs/Indiana/IM_IN_TB_20_04-30-2026.pdf.

[22] Indiana Michigan Power, "Tariff I.P. (Industrial Power)," at PDF page 90, available at https://www.indianamichiganpower.com/lib/docs/ratesandtariffs/Indiana/IM_IN_TB_20_04-30-2026.pdf.

[23] Indiana Michigan Power, "Tariff I.P. (Industrial Power)," at PDF page 89, available at https://www.indianamichiganpower.com/lib/docs/ratesandtariffs/Indiana/IM_IN_TB_20_04-30-2026.pdf.

[24] Indiana Michigan Power, "Tariff I.P. (Industrial Power)," at PDF page 89, available at https://www.indianamichiganpower.com/lib/docs/ratesandtariffs/Indiana/IM_IN_TB_20_04-30-2026.pdf.

[25] Public Service Commission of the State of Missouri, Case No. ET-2025-0184, Ameren Missouri, *Tariff Letter and Filing*, December 5, 2025, at 9, available at https://www.efis.psc.mo.gov/Document/Display/859648.

months in the remaining term of the load ramp period plus 60 months (5 years).[26] If the customer leaves after the load ramp period, the Exit Fee would equal to the nominal value of the applicable minimum monthly bill multiplied by the lesser of (a) 60 months or (b) number of months in the remaining term.[27]

E. Recovery of Study Costs

Multiple PUCs have approved tariffs or contracts between utilities and large load customers that require customers to pay for the energization study cost or their portion of a joint study. This is because the utility's study to determine infrastructure investments and upgrades necessary to provide power to large load customers can pose a significant cost.

Examples:

- Florida Power & Light Large Load Contract Service (LLCS-1) and Large Load Contract Service-2 (LLCS-2) tariffs **(approved)** require customers of 50 MW or more to pay for the utility to "undertake system impact and engineering studies… associated with interconnecting and serving the Customer's Contract Demand" and also "accept the results of those System Studies" and thus would be non-negotiable if they choose to interconnect.[28]
- Under the New York Municipal Power Agency tariff for High Density Load (Rider A – High Density Load Service) **(approved)**, the customer is required to pay to the utility "reasonable costs of conducting the feasibility study" for identifying what may be needed to deliver service to the large load customer.[29]

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[26] Public Service Commission of the State of Missouri, Case No. ET-2025-0184, Ameren Missouri, *Tariff Letter and Filing*, at 11, available at https://www.efis.psc.mo.gov/Document/Display/859648.

[27] Public Service Commission of the State of Missouri, Case No. ET-2025-0184, Ameren Missouri, Tariff Letter and Filing, at 11, available at https://www.efis.psc.mo.gov/Document/Display/859648.

[28] Florida Power & Light Company Rate Schedules, *Large Load Contract Service-1*, at PDF page 144, and *Large Load Contract Service-2*, at PDF pages 142, 144, and 147, available at https://www.fpl.com/content/dam/fplgp/us/en/rates/pdf/electric-tariff-section8.pdf.

[29] New York Municipal Power Agency, *New York Municipal Power Agency Generic Tariff*, "Rider A (Rates and Charges for Customers Requesting High Density Load ('HDL') Service"), March 19, 2018, at PDF page 96-99, available at https://ets.dps.ny.gov/ets_web/search/showPDF.cfm?M%3AIS%20%3B%2A%29LOUNWD%5CJ%5E8

F. Infrastructure Investment Assignment

To reduce stranded asset and cost shift risks, multiple PUCs have approved large load tariffs with specific conditions. For example, as discussed further below, some tariffs require significant upfront customer infrastructure investments before service is provided, while other require a monthly charge for additional infrastructure required to provide service to the customer. In addition, some tariffs subject the large load customer to a different transmission cost methodology:

- The New York Municipal Power Agency Rider A – High Density Load Service **(approved)** requires the large load customer to pay the "entire cost of any new facilities necessary to supply the requested service… in cash, before new facilities will be constructed."[30] For the first ten years of service, the customer "will receive a refund equal to the lesser of the annual non-supply related revenues from the customer," or one-tenth of the paid contribution.[31]
- The Arkansas Electric Cooperative Corporation (AECC)'s new Transmission Extension of Facilities Tariff **(approved)** requires power-intensive users (PIUs), defined as a retail customer with a demand exceeding 50 MW, to pay for new transmission upgrades and extensions, called a contribution in aid of construction (CIAC).[32] Under this tariff, a PIU has to pay one divided by the total number of months of its contract length with AECC of the investment that AECC has to make to supply the Member Cooperative serving the PIU.[33] For instance, if the contract length is 5 years or 60 months, then the PIU must pay 1/60th of the infrastructure investment cost every month.[34] The CIAC is not generally refundable, unless

%2B%22%2B5%2F0MD%2F0%28%23%21N%29S%5CCVU2R%2AK%3AR%5CA%5B%2A2H%22N%5EAISF%20XNY%0A%27N7JEJK%5F%2CB%40%20%20%0A.

[30] New York Municipal Power Agency, *Generic Tariff*, "Rider A," at PDF pages 96-99.

[31] New York Municipal Power Agency, *Generic Tariff*, "Rider A," at PDF pages 96-99.

[32] Arkansas Electric Cooperative Corporation (AECC), *Index of Rate and Policy Schedules*, September 9, 2025, at 34-38 (Transmission Extension of Facilities Tariff), available at https://apps.apsc.arkansas.gov/tariffs/2_elec_1.PDF.

[33] AECC, *Index of Rate and Policy Schedules*, at 34-38 (Transmission Extension of Facilities Tariff), available at https://apps.apsc.arkansas.gov/tariffs/2_elec_1.PDF.

[34] AECC, *Index of Rate and Policy Schedules*, at PDF 34-38 (Transmission Extension of Facilities Tariff), available at https://apps.apsc.arkansas.gov/tariffs/2_elec_1.PDF.

any of the following applies. (a) If the estimated CIAC is higher than the actual costs, the tariff allows a downward adjustment.[35] (b) "If approved by the Commission… AECC may waive all or a portion of the CIAC or negotiate a returnable CIAC where AECC determines that doing so result in a net economic benefit to all other Member Cooperatives. A waiver may be requested for any remaining portion of a CIAC previously established by this tariff."[36] (c) The AECC may adjust the CIAC by a proportional share if other similar PIUs also use the extension.[37]

- Customers on Black Hill Energy's Schedule Large Power Contract Service (LPCS) **(approved)** are not able to participate in the Transmission Cost Adjustment Mechanism that the utility uses to calculate transmission cost based on customer classes, instead the Schedule states "the transmission costs related to the Company's transmission system will be directly assigned to the Customer based on the Customer's load ratio share."[38] This tariff does not have any language regarding a refund schedule or mechanism for transmission costs triggered by interconnecting an applicable customer.[39]

G. Customer Credit Rating and/or Collateral Requirement

Some large load tariffs include provisions for a minimum customer credit rating and/or collateral requirement, which can interact with each other.

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[35] AECC, *Index of Rate and Policy Schedules*, at PDF 36 (Transmission Extension of Facilities Tariff), available at https://apps.apsc.arkansas.gov/tariffs/2_elec_1.PDF.

[36] AECC, *Index of Rate and Policy Schedules*, at PDF 37, available at https://apps.apsc.arkansas.gov/tariffs/2_elec_1.PDF.

[37] AECC, *Index of Rate and Policy Schedules*, at PDF 37, available at https://apps.apsc.arkansas.gov/tariffs/2_elec_1.PDF.

[38] Cheyenne Light, Fuel, and Power Company d/b/a Black Hills Energy, *Schedule of Rates for Electric Service,* "Large Power Contract Service," December 13, 2022, at PDF 31, available at https://www.blackhillsenergy.com/sites/blackhillsenergy.com/files/clfp_electric.pdf.

[39] Black Hills Energy, *Schedule of Rates for Electric Service,* "Large Power Contract Service," December 13, 2022, at PDF 27-32, available at https://www.blackhillsenergy.com/sites/blackhillsenergy.com/files/clfp_electric.pdf.

Examples:

- Customers under the Ameren Missouri's Large Load Customer Service Rate schedule **(approved)** must provide a collateral equal to 2 years of minimum monthly bill.[40]
- Dominion Energy's The GS-5 rate class, **approved** by the Virginia State Corporation Commission, requires $1.5 million/MW in collateral, and a reduction in collateral of up to 70% based on the customer's established credit.[41] Since the contract length per this rate schedule is 14 years, 1/14th of the collateral agreement would be released each year throughout the contract term.[42]

H. Minimum Load Requirements

Utility tariffs can include an MW threshold for service eligibility. Utilities can further specify whether the threshold applies to an individual site or a customer's aggregated load within a specific geographic range to prevent data center customers from circumventing eligibility requirements.

Examples (from low threshold to high):

- Xcel Energy Minnesota's Competitive Response Rider (**approved** and effective 2018) – minimum of 2 MW.[43]
- AEP Ohio's Data Center Power Tariff (**approved** and effective July 2025): minimum of 25 MW in a single location or an aggregated total customer capacity in the service territory of 25 MW.[44] If the customer has additional non-data center load at the same location "that would otherwise be

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[40] Missouri Public Service Commission, Case no. ET-2025-0184 – Item 191, Ameren Missouri, *Tariff Letter and Filing* (Large Primary Service Rate), December 5, 2025, at PDF page 14, available at https://efis.psc.mo.gov/Document/Display/859644; Missouri Public Service Commission, *Order Approving Tariff Revision,* December 19, 2025, at 1, available at https://www.efis.psc.mo.gov/Document/Display/860789.

[41] VSCC, Case no. PUR-2025-00058 *Final Order*, November 25, 2025, at 25, available at https://www.scc.virginia.gov/docketsearch/DOCS/89g601!.PDF.

[42] VSCC, Case no. PUR-2025-00058 *Final Order*, at 24-25, available at https://www.scc.virginia.gov/docketsearch/DOCS/89g601!.PDF.

[43] Northern Stats Power Company, *Minnesota Electric Rate Book-MPUC NO. 2*, "Competitive Response Rider," October 1, 2017, at PDF page 152, available at https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/MN/Me_Section_5.pdf.

[44] Ohio Power Company (AEP Ohio), "Schedule DCT (Data Center Tariff)," April 10, 2026, at PDF page 114, available at https://www.aepohio.com/lib/docs/ratesandtariffs/Ohio/AEP_Ohio_Tariff_Bookv1.pdf

billed under the General Service or other applicable Schedule," then the customer "shall have the option of separately metering its Data Center and non-Data Center loads (if technically feasible) and paying for those loads through separate customer accounts."[45]

- Entergy Mississippi's Large Power Rate Schedule (**approved** and effective December 2018): minimum of 30 MW.[46]
- Appalachian Power Company and Wheeling Power Company's Large Capacity Power Schedule **(approved)**: applies to any new load with a contract capacity of at least 100 MW at a single site or 150 MW on an aggregated basis.[47]

I. Minimum Load Factor

Utility tariffs can specify the ratio of average load (MW) and peak load (MW) during a particular period (e.g., monthly, seasonally, or annually) that a customer is required to maintain. Higher load factors, indicating more consistent energy usage, can "smooth out demand peaks to lower the strain on the power infrastructure and increase reliability."[48] A mandatory minimum load factor incentivizes reduced fluctuations in load, allowing the utility to more accurately forecast demand and plan accordingly.

Examples:

- Otter Tail Power's Super Large General Service Rate **(approved)**: 80% minimum "expected" load factor.[49]
- Evergy Missouri Metro's Special High Load Factor Market Rate (**approved** and effective July 2023): minimum annual

[45] AEP Ohio, "Schedule DCT," at PDF page 114, available at https://www.aepohio.com/lib/docs/ratesandtariffs/Ohio/AEP_Ohio_Tariff_Bookv1.pdf.
[46] Mississippi Public Service Commission, Entergy Mississippi, LLC, *Large Power Rate Schedule LPR-2*, December 1, 2018, at 1, available at https://www.entergymississippi.com/wp-content/uploads/eml_lpr.pdf.
[47] Public Service Commission of West Virginia, Appalachian Power Company and Wheeling Power Company, *Rate Schedules Terms and Conditions of Service Governing Sales of Electricity in West Virginia*, "Schedule L.C.P., Large Capacity Power," September 29, 2025, at PDF page 70, available at https://www.appalachianpower.com/lib/docs/ratesandtariffs/WestVirginia/RET_Tariff_Sheets_Eff_12-12-25.pdf.
[48] Sherwood, Stacy, *Review of Large Load Tariffs to Identify Safeguards and Protections for Existing Ratepayers* (*Review of Lard Load Tariffs*), Energy Futures Group (Jan. 28, 2025), at 7, available at: https://energyfuturesgroup.com/wp-content/uploads/2025/01/Review-of-Large-Load-Tariffs-to-Identify-Safeguards-and-Protections-for-Existing-Ratepayers-Report-Final.pdf.
[49] Minnesota Public Utilities Commission, Otter Tail Power Company, *Super Large General Service Applications and Eligibility Requirements*, July 1, 2022, at 1, available at https://www.otpco.com/media/1pedapr4/mn_1006.pdf.

load factor of 85% at full load.[50] During the startup period (not to exceed 5 years), the "Customer must be able to demonstrate the average of its Monthly Load Factors for the immediately preceding twelve months is 0.85 or greater."[51] Evergy Missouri Metro calculates load factor[52] as the following:

$$\text{Annual Load Factor} = \frac{\text{Customer's Annual Energy Usage}}{\text{Customer's Annual Noncoincident Peak Demand} * \text{Number of Hours in the Year}}$$

$$\text{Monthly Load Factor} = \frac{\text{Customer's Monthly Energy Usage}}{\text{Customer's Monthly Noncoincident Peak Demand} * \text{Number of Hours in the Month}}$$

- Montana-Dakota Utilities' High Density Contracted Demand Response Rate (**approved** and specifically targets blockchain customers): 85% minimum load factor.[53]
- Florida Power & Light's Large Load Contract Service (LLCS-1) and Large Load Contract Service (LLCS-2) (**approved** and effective January 2026): 85% minimum load factor.[54]

In addition to a minimum load factor, some utilities also impose a minimum power factor. A power factor, defined as the ratio of real power (watts) to apparent power (volt-amperes), indicates the effectiveness of the use of receiving power by a load.[55] Requiring large load customers to maintain a specific power factor range can decrease system loses

[50] Missouri Public Service Commission, Evergy Metro, Inc. d/b/a Evergy Missouri Metro, *Special High-Load Factor Market Rate, Schedule MKT* (Special High-Load Factor Market Rate), July 13, 2023, at 1, available at https://www.evergy.com/-/media/documents/billing/missouri/detailed_tariffs_mo/special-high-load-factor-market-rate.pdf.

[51] Missouri Public Service Commission, Evergy Metro, Inc. d/b/a Evergy Missouri Metro, *Special High-Load Factor Market Rate, Schedule MKT* ("Special High-Load Factor Market Rate"), July 13, 2023, at 1, available at https://www.evergy.com/-/media/documents/billing/missouri/detailed_tariffs_mo/special-high-load-factor-market-rate.pdf.

[52] Evergy Metro, "Special High-Load Factor Market Rate," at 1, available at https://www.evergy.com/-/media/documents/billing/missouri/detailed_tariffs_mo/special-high-load-factor-market-rate.pdf.

[53] Montana-Dakota Utilities Co., "High Density Contracted Demand Response Rate 45," September 1, 2024, at 1, available at https://www.montana-dakota.com/wp-content/uploads/PDFs/Rates-Tariffs/SouthDakota/Electric/SD_Electric45.pdf.

[54] Florida Power & Light Company, *Large-Load Contract Service-1 (LLCS-1),* January 1, 2026, at PDF 142 and *Large Load Contract Service-2 (LLCS-2)*, January 1, 2026, at PDF page 145, available at https://www.fpl.com/content/dam/fplgp/us/en/rates/pdf/electric-tariff-section8.pdf.

[55] Sherwood, *Review of Large Load Tariffs,* at 7.

and assist with voltage regulation, which has the potential to reduce energy costs and facilitate the connection of additional load onto the system.[56]

Example:

- Montana-Dakota Utilities' High Density Contracted Demand Response Rate (**approved** and specifically targets blockchain customers): allows the utility to "reserv[e] the right" to require customers to install equipment that enables it to maintain a power factor between "97% lagging and 97% leading."[57]

J. Contract Capacity/Energy Obligation

Utility tariffs can obligate large load customers to pay for a specified amount of capacity (MW) or energy (MWh), regardless of actual usage (aka, minimum demand charge).

Examples:

- AEP Ohio's Data Center Power Tariff (**approved** July 2025): after any ramp-up period, customer will be charged the greater of "(a) 85% of the customer's highest previously established monthly billing demand during the past 11 months or (b) the customer's 'Minimum Demand' [further defined below]."[58]
- Dominion Energy's added provision to various large general service rates **(approved)**: added minimum demand charges to Rate Schedules 6, 1-TS, GS-3, GS-4, Schedule 10, and market-based Rate Schedules MBR and SCR, which charges customers for the greater of (a) actual demand or (b) the minimum percentage of their contract demand, specified as "85% for the transmission and distribution functions, and 60% for the generation function."[59]

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[56] Sherwood, *Review of Large Load Tariffs,* at 14.

[57] Montana-Dakota Utilities Co., "High Density Contracted Demand Response Rate 45*,"* September 1, 2024, at 2, available at https://www.montana-dakota.com/wp-content/uploads/PDFs/Rates-Tariffs/SouthDakota/Electric/SD_Electric45.pdf.

[58] AEP Ohio, "Schedule DCT," at PDF pages 115-116, available at https://www.aepohio.com/lib/docs/ratesandtariffs/Ohio/AEP_Ohio_Tariff_Bookv1.pdf.

[59] Dominion Energy, *Application of Virigina Electric and Power Company for a 2025 biennial review of the rates, terms, and conditions for the provision of generation, distribution and transmission services*

K. Resizing or Reassignment of Contract Capacity/Energy Obligation

In addition to specifying a minimum demand charge, several utility tariffs also contain pathways for large load customers to resize their contract capacity and/or energy obligations under certain terms and conditions. Tariff exit clauses can also include an obligation to reassign a portion or all of a customer's load and financial obligations to another.

Examples:

- Appalachian Power Company and Wheeling Power Company's Large Capacity Power (L.C.P Schedule) and Industrial Power Service (Schedule I.P) **(approved)**: after the initial five years of the contract and with 42 months written notice, customers may reduce their contract capacity by no more than 20%, unless mutually agreed to by the customer and utility. No exit fee or penalty is required.[60]
- Indiana Michigan Power's Industrial Power Tariff (**approved** February 2025): the approved Settlement Agreement allows a large load customer to reduce its contract capacity by "20% any time after the first five years" with "at least 42 months written notice" and requires a capacity reduction fee.[61] The fee "shall be calculated as the nominal value of the remaining Minimum Charge for the terminated/reduced capacity in excess of the 20% allowed reduction for the first year of the Exit Fee Period; and for any remaining year of the Exit Fee Period the Exit Fee shall be calculated in the same manner as the first year, minus the OSS/PJM Rider's (or the same cost

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pursuant to § 56-585.1 A of the Code of Virginia, March 31, 2025, at 12, available at https://www.scc.virginia.gov/docketsearch/DOCS/84s201!.PDF; issued in Case No. PUR-2025-0058.

[60] Appalachian Power Company and Wheeling Power Company, "Schedule L.C.P.," at PDF page 71, available at https://www.appalachianpower.com/lib/docs/ratesandtariffs/WestVirginia/RET_Tariff_Sheets_Eff_12-12-25.pdf.

[61] Indiana Michigan Power, "Tariff I.P. (Industrial Power)," February 19, 2026, at PDF page 89, available at https://www.indianamichiganpower.com/lib/docs/ratesandtariffs/Indiana/IM_IN_TB_20_04-30-2026.pdf.

addressed in another rider's) contribution to the Minimum Charge."[62]

- AEP Ohio's Data Center Tariff (**approved** July 2025): for new load only, after the "initial period" of the contract (defined as the Load Ramp Period plus 8 years, so customer with a 4-year Ramp Period will have an initial period of 12 years), the customer or utility is allowed to request a modification to the contract capacity by written notice no later than three years prior to the requested modification date.[63] The customer may be required to pay an exit fee.[64]
- Rocky Mountain Institute (RMI) 2025 – in its review of 65 large load tariffs, RMI found that 12 contained resizing clauses for contract capacity.[65] RMI states that allowing large load customers to amend their contract capacity or reassign their obligation to another customer introduces the flexibility for data centers to react to "changing business needs, conditions, and innovations, including those in efficiency and flexibility."[66] Moreover, data centers may be incentivized to find replacements for their surplus capacity, "creating an opportunity for another large customer to pay for costs incurred and use the grid capacity, limiting stranded assets" borne by other ratepayers.[67]

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[62] Indiana Michigan Power, "Tariff I.P.*,"* at PDF page 89, available at https://www.indianamichiganpower.com/lib/docs/ratesandtariffs/Indiana/IM_IN_TB_20_04-30-2026.pdf.

[63] AEP Ohio, "Schedule DCT," at PDF page 117, available at https://www.aepohio.com/lib/docs/ratesandtariffs/Ohio/AEP_Ohio_Tariff_Bookv1.pdf.

[64] AEP Ohio, "Schedule DCT (Data Center Tariff)," at PDF page 117, available at available at https://www.aepohio.com/lib/docs/ratesandtariffs/Ohio/AEP_Ohio_Tariff_Bookv1.pdf.

[65] Perez, Alyssa et. al, *Large Energy Users Want Power. Here's How to Protect Other Ratepayers from the Costs*, Rocky Mountain Institute (RMI)*,* November 7, 2025, available at https://rmi.org/large-energy-users-want-power-heres-how-to-protect-other-ratepayers-from-the-costs/.

[66] Perez at al., *Large Energy Users Want Power,* available at https://rmi.org/large-energy-users-want-power-heres-how-to-protect-other-ratepayers-from-the-costs/.

[67] Perez at al., *Large Energy Users Want Power,* available at https://rmi.org/large-energy-users-want-power-heres-how-to-protect-other-ratepayers-from-the-costs/.

L. Assign Generation and Other Related Costs

PUCs and utilities can pursue methods for assigning data center customers' interconnection costs (see examples in #6) and generation costs. Examples of the latter and other attempts to appropriately assign data center-related costs include:

- Black Hills Energy's Large Power Contract Service (**approved** in 2016, updated 2024): developed collaboratively with Microsoft, this service agreement requires customers to provide their own capacity through customer-owned generators or renewable resources, Purchased Power Agreements, battery storage, etc. (see tariff page 2 for more options).[68] According to the Edison Electric Institute, this tariff was designed to "ensure large-load growth does not impact other ratepayers."[69]
- Evergy Missouri Metro's Special High-Load Factor Market Rate (Schedule MKT) (**approved** and effective July 2023) – in order to ensure that "non-MKT customers shall be held harmless from any deficiency in revenues provided by any customer served under this tariff or from any stranded investment or cost(s)" the utility "will make provision to uniquely identify the costs and revenues for each respective Special High-Load Factor Market Rate Contract within its books and records."[70] During rate proceedings, "the portion of the [utility's] revenue requirement associated with the costs to serve the Customer shall be assigned to the Customer."[71] If there is shortfall in the MKT customer's

[68] Cheyenne Light, Fuel and Power Company d/b/a Black Hill Energy, "Large Power Contract Service, Rate Schedule LPCS," June 1, 2024, at 2, available at https://ir.blackhillscorp.com/static-files/78c946a9-fe41-4c86-9f80-7a4c1bc689f9 and Edison Electric Institute (EEI), "Large Load Projects and Tariffs (March 2026)," at 14, available at https://www.eei.org/-/media/Project/EEI/Documents/Issues%20and%20Policy/List%20of%20Large%20Customer%20Projects%20and%20Tariffs.

[69] Edison Electric Institute (EEI), "Large Load Projects and Tariffs (March 2026)," at 14-15, available at https://www.eei.org/-/media/Project/EEI/Documents/Issues%20and%20Policy/List%20of%20Large%20Customer%20Projects%20and%20Tariffs.

[70] Evergy Metro, "Special High-Load Factor Market Rate," at PDF page 4.

[71] Evergy Metro, "Special High-Load Factor Market Rate," at PDF page 4.

revenue, then the utility will "make an additional revenue adjustment covering the shortfall to the revenue requirement calculation through the true-up period…."[72]

- Kentucky Power's Economic Development Rider ("EDR") (effective January 2021 and **canceled** January 16, 2024): if the utility needs to procure additional capacity to serve a customer under this tariff, it will procure more and "the cost of capacity procured on behalf of the customer shall reduce on a dollar-for-dollar basis the customer's IBDD [incremental billing demand discount] and SBDD [supplemental billing demand discount]."[73]
- Portland General Electric's (PGE's) updated Rules C and I (**approval pending**): proposes updates to marginal cost studies to include, amongst other changes, a Peak Growth Modifier "that adjusts the allocation of transmission and fixed generation costs toward customer classes that are contributing most to system peak *growth* in recent years, not simply their contribution to the system peak for the target year…" This results in "customer classes contributing to PGE's system peak growth, like PGE's new large data center class and to a lesser extent, the residential class, will be allocated costs based on growth and size and not simply size."[74]

M. Behind-the-Meter Resources

Generation resources or storage systems located on a customer's side of a utility meter, or "behind-the-meter" resources, can reduce data centers' interconnection timeline and, potentially, forego a utility's need to invest in additional capacity to serve new load. For example, data centers that co-locate at an existing power plant can receive service

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[72] Evergy Metro, "Special High-Load Factor Market Rate," at PDF page 4.

[73] Kentucky Public Service Commission, Kentucky Power Company, *Tariff E.D.R. (Economic Development Rider)*, April 9, 2021, at PDF page 1, available at https://psc.ky.gov/tariffs/Electric/Kentucky%20Power%20Company/Cancelled%20Tariff%20Pages/2024/Tariff%20E.D.R.%20(Economic%20Development%20Rider)/01-16.pdf.

[74] Portland General Electric, *Opening Testimony in UM 2377 Investigation into Marginal Cost Study Treatment of Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I,* August 11, 2025, at 10, available at https://edocs.puc.state.or.us/efdocs/HTB/um2377htb338993027.pdf.

through a mixture of customer-owned, on-site solar and storage resources and, as needed, electricity from the power plant.[75]

Examples:

- Pacific Power's Schedule 47 (Large General Service Partial Requirements) **(approved)**: applicable to large, nonresidential customers with self-generation capacities of at least 1 MW who require at least 1 MW of "standby electric service" from the utility.[76] Allows for reduced demand charges, among other adjustments, by setting the customer's baseline demand as the demand supplied by the utility when the customer's "generator is regularly operating as planned."[77] Also allows customers with at least 15 MW of self-generation capacity to receive bill credits for supplying their own spinning and/or supplemental reserves.[78] Contract term is at least 1 year.[79]
- Ohio AEP's Data Center Tariff (DCT) **(approved)**: behind-the-meter generation cannot exceed the customer's contract capacity by more than 1 MW. If the customer uses behind-the-meter generation to offset its contract capacity, then certain restrictions apply.[80]
- Enchanted Rock's Bridge-to-Grid - this energy solutions provider offers a behind-the-meter service that provides large load customers with interim power until they can connect to

[75] Chojkiewicz, Emilia, et al., *Utilizing Noncoincident Needs to Site Data Centers with Solar+Storage at Existing Gas Plants*, Energy Institute at HAAS, Energy Institute WP 356, February 2026, at PDF page 2, available at https://haas.berkeley.edu/wp-content/uploads/archive/WP356.pdf.

[76] Pacific Power, "Schedule 47: Large General Service Partial Requirements 1,000 kW and Over Delivery Service," January 1, 2025, at 1, available at https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/rates/047_Large_General_Service_Partial_Requirements_1_000_KW_and_Over_Delivery_Service.pdf.

[77] Pacific Power, "Schedule 47," at 2, available at https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/rates/047_Large_General_Service_Partial_Requirements_1_000_KW_and_Over_Delivery_Service.pdf.

[78] Pacific Power, "Schedule 47," at 3, available at 047_Large_General_Service_Partial_Requirements_1_000_KW_and_Over_Delivery_Service.pdf.

[79] Pacific Power, "Schedule 47," at 6, available at 047_Large_General_Service_Partial_Requirements_1_000_KW_and_Over_Delivery_Service.pdf.

[80] AEP Ohio, "Schedule DCT," at PDF page 119, available at https://www.aepohio.com/lib/docs/ratesandtariffs/Ohio/AEP_Ohio_Tariff_Bookv1.pdf

the grid and receive service through a utility.[81] In San Jose, California, Enchanted Rock is building a renewable natural gas microgrid to provide backup power for a Microsoft data center.[82]

N. Flexible Service: Interruption Terms and Demand Response Programs

Utilities can require load large customers to curtail demand under certain conditions through an interruptible tariff, service agreement terms, and/or demand response (DR) programs. A utility's ability to interrupt new load may expand its capability to connect large load customers when system capacity is limited, as well as increase system reliability and reduce capacity costs.[83] Flexible service for large load is also a means to uphold the Commission's Electric Rate Principle Five, which states "rates should encourage customer behaviors that improve electric system reliability in an economically efficient manner."[84] In service areas where an interruptible tariff is not available, utilities have inserted interruption terms into individual customer contracts.

Interruptible tariff and terms examples:

- Montana-Dakota Utilities' High Density Contracted Demand Response Rate (**approved** and specifically targets blockchain customers): requires the interruption of service for up to 200 hours per year, or "as included in the electric service agreement."[85] Electric service agreements need to specify:

  > "a. The number of hours a customer may be interrupted in an annual period.

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[81] Enhanced Rock, "Bridge power for largescale energy needs," available at https://erock.com/bridge-to-grid/.

[82] Norris, Tyler, et al., *Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems*, Duke, Nicholas Institute for Energy, Environment & Sustainability, 2025, at 14, available at https://nicholasinstitute.duke.edu/sites/default/files/publications/rethinking-load-growth.pdf.

[83] Sherwood, *Review of Large Load Tariffs,* at 9 and 15.

[84] D.23-04-040, *Decision Adopting Electric Rate Design Principles and Demand Flexibility Design Principles*, May 3, 2023, Ordering Paragraph 1(e) at 36.

[85] Montana-Dakota Utilities Co., "High Density Contracted Demand Response Rate 45," September 1, 2024, at 1, available at https://www.montana-dakota.com/wp-content/uploads/PDFs/Rates-Tariffs/SouthDakota/Electric/SD_Electric45.pdf

b. The length of time (in minutes) in which the customer must interrupt service following receipt of Company signal.

c. The firm load amount not subject to interruption.

d. The deposit amount required prior to the commencement of service under this rate schedule."

Additional terms include: a non-performance penalty for failure to interrupt service when requested of at least $10/kW applicable to demand specified in service agreement or "the appropriate reallocation of any penalties imposed on the Company [Montana-Dakota Utilities Co.] by the Midcontinent Independent System Operator (MISO)…."[86] A second failure to interrupt when requested within a 12-month period may result in removal from tariff in addition to the penalty.[87]

- Black Hills Energy's Blockchain Interruptible Service (BCIS) (**approved**): similarly specifies which terms must be included in a customer's individual service contract with the utility, such as the size of interruptible load, notice of planned interruption, duration, maximum hours per year, and penalties for failures to respond.[88]

Demand response/flexible programs examples:

- ERCOT's Large Flexible Load (LFL) Task Force **(still active)**: since 2022, ERCOT has signed voluntary curtailment agreements with large load customers (data center, cryptomining, and other industrial customers) to reduce load

[86] Montana-Dakota Utilities Co., "High Density Contracted Demand Response Rate 45," September 1, 2024, at 2, available at https://www.montana-dakota.com/wp-content/uploads/PDFs/Rates-Tariffs/SouthDakota/Electric/SD_Electric45.pdf.

[87] Montana-Dakota Utilities Co., "High Density Contracted Demand Response Rate 45," September 1, 2024, at 2, available at https://www.montana-dakota.com/wp-content/uploads/PDFs/Rates-Tariffs/SouthDakota/Electric/SD_Electric45.pdf.

[88] Wyoming Public Service Commission, Cheyenne Light, Fuel and Power Company d/b/a Black Hills Energy, *Electric Rates Blockchain Interruptible Service (BCIS)*, April 1, 2023, at 1, available at https://ir.blackhillscorp.com/static-files/5c33d769-2d19-43f8-8898-a37af25481ef.

during periods of high system demand or low capacity.[89] By the end of 2025, ERCOT estimates that it will have approved 9,500 MW of LFL demand capacity.[90]

- AEP Ohio's Data Center Tariff **(approved)**: maintains the utility's right, via Ohio Administrative Code 4901:1-10-16, to disconnect or curtail load during emergencies.[91]
- PG&E's Flex Connect Pilot **(active)** and prospective T-Flex**:** Flex Connect enables distribution-level customers who require system upgrades for additional or new demand to connect to PG&E's grid if they can adjust their load based on the availability of capacity, implemented via a local site energy management system that sends hourly power limit forecasts a day in advance.[92] While Flex Connect is marketed towards EV charging load, PG&E announced it plans to launch a similar program later this year for transmission system customers called T-Flex, which "would allow large, flexible loads like data centers to connect sooner by adjusting usage during rare grid constraints."[93]
- Google: in Oregon, Nebraska, Taiwan, and Europe, Google data centers have participated in DR programs and reduced non-time sensitive tasks during periods of grid stress.[94]

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[89] U.S. Energy Information Administration (EIA), "Data centers and cryptocurrency mining in Texas drive strong power demand power," October 3, 2024, available at https://www.eia.gov/todayinenergy/detail.php?id=63344#

[90] EIA, "Data centers and cryptocurrency mining," October 3, 2024, available at https://www.eia.gov/todayinenergy/detail.php?id=63344#.

[91] AEP Ohio, "Schedule DCT," at PDF page 119, available at https://www.aepohio.com/lib/docs/ratesandtariffs/Ohio/AEP_Ohio_Tariff_Bookv1.pdf.

[92] Pacific Gas and Electric Company (PG&E), "PG&E Flex Connect Pilot," available at https://www.pge.com/assets/pge/docs/clean-energy/electric-vehicles/flexible-service-connection-pilot-overview.pdf. Note – this program targets residential EV charger upgrades, unsure if it is able to accommodate large load customers.

[93] Sarah, Rachel, "Why Grid Flexibility is now Essential – and How PG&E is Delivering it," Pacific Gas and Electric Company (PG&E), May 6, 2026, available at https://www.pge.com/en/newsroom/currents/future-of-energy/why-grid-flexibility-is-now-essential---and-how-pg-e-is-deliveri.html.

[94] Mehra, Varun and Hasegawa, Raiden, *Supporting Power Grids with Demand Response at Google Data Centers*, Google Cloud Blog, October 3, 2023, available at https://cloud.google.com/blog/products/infrastructure/using-demand-response-to-reduce-data-center-power-consumption .

- Enel X: used back-up power supplies (on-site generation and storage resources) to participate in DR programs in North America, Ireland, Australia, South Korea, and Japan.[95]

O. Clean Energy Tariffs and Riders

A number of states have passed optional tariff options or riders for large loads to receive more electricity sourced from carbon-free or renewable sources.

Examples:

- Dominion Energy's Schedule CFG Carbon-Free or Renewable Generation Supply Service Experimental Tariff **(approved)**: optional tariff applies to customers under certain non-residential tariff, including tariffs for large load customers.[96] It allows large loads to purchase up to 100% of net carbon free or renewable generation, and is limited to only 50 customers.[97]
- Salt River Project's E-67 Standard Price Plan for Large Load Substation Large General Service **(approved)**: customers can elect to participate in the Energy Attribute Certificate Rider or the Carbon Reduction Rider.[98]

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[95] Enel X, "How Data Center Support the Power Grid with Ancillary Services?" available at https://www.enelx.com/tw/en/resources/how-data-centers-support-grids.

[96] Customers on Dominion Energy's Schedule GS-1, Schedule GS-2, Schedule GS-2T, Schedule GS-3, Schedule GS-4, Schedule 10, Schedule 27, Schedule 28, Schedule MBR, and Schedule SCR can elect to also be on Schedule CFG. Not all of these eligible schedules are large load customers, but some are. Schedule GS-3 Large General Service Secondary Voltage and GS-4 Large General Service Primary Voltage apply to customers with peak demand at or more than 0.5 MW, Schedule 10 Large General Service applies to customers with maximum demand at or more than 25 MW, and Schedule MBR Large General Service Market-Based Rate applies to customers with peak demand at or more than 5 MW. See Virginia State Corporation Commission, Virginia Electric and Power Company aka Dominion Energy, *Entire Filed Tariff*, at PDF pages 264, 186, 202, 250, 211, available at https://www.dominionenergy.com/-/media/content/rates-and-tariffs/pdfs/virginia/shared/entire-filed-tariff.pdf?rev=4717a57ce7fa427996787a8de34536e1&hash=5EF3D8DD6FA0FB54E8AD04E95060D276.

[97] Virginia State Corporation Commission, Virginia Electric and Power Company aka Dominion Energy, *Schedule CFG Carbon-Free or Renewable Generation Supply Service (Experimental)*, February 1, 2025, at 1 and 3, available at https://www.dominionenergy.com/-/media/content/rates-and-tariffs/pdfs/virginia/large-business/schedule-cfg.pdf?rev=7aeef26842db4e9098dd0e77a920a482&hash=665E8C81D997FE3479665B648E297C24.

[98] See Salt River Project, *Standard Electric Price Plans: Prices Effective with November 2025 Billing Cycle*, at 162-169 (E-67), 178-179 (Energy Attribute Certificate Rider), 172-173 (Carbon Reduction Rider), available at https://www.srpnet.com/assets/srpnet/pdf/price-plans/2024/2025-Ratebook.pdf.

- NV Energy's Clean Transition Tariff **(approved)**: allows large customers with an annual hourly load of 5 MW or more to executive an Energy Supply Agreement (ESA) with the utility to source new clean energy resources.[99] The PUC of Nevada would determine whether the ESA is in the public interest and if non-participating customers will experience increased costs or forego any benefits as a result before approving it.[100] An interesting provision is that under the ESA, the term length of the contract must match the lifetime of the new clean energy facility ("The Energy Supply Agreement shall… [h]ave a term length that is the same term as the life of the CTT Facility(s), unless otherwise specified and explained in the Application")[101]

III. PROMOTING ELECTRIFICATION, BENEFICIAL LOAD GROWTH, AND LOAD FLEXIBILITY FOR INDUSTRIAL CUSTOMERS

According to the American Council for an Energy-Efficient Economy (ACEEE), rates designed to specifically support industrial customers' electrification are not common, with states instead using tax credits to incentivize technology like heat pumps.[102] The only large load electrification incentive rates identified by ACEEE are in British Columbia, Canada (see example section below.)

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[99] Public Utilities Commission of Nevada (PUCN), *Re: Docket No. 24-05022 – Application of Nevada Power Company d/b/a NV Energy, filed under Advice Letter No. 547, to implement Clean Transition Tariff Schedule No. CTT to allow eligible customers to receive bundled electric service from new clean energy resources*, July 11, 2025, Schedule No. CTT Clean Transition Tariff, at PDF pages 4 and 6, available at https://puc-onbase.nv.gov/api/Document/AR1u41K1Yay0ARZ4djTD%C3%89dZof8NgEVlGZasxD%C3%890kammtZoyCH2mLGtUzJhvnTwG6%C3%81qmwaLh0x8JqN5hF6DgFnW0%3D/?OverlayMode=View

[100] PUCN, *Re: Application of Nevada Power Company, filed under Advice Letter No. 547, to implement Clean Transition Tariff Schedule No. CTT*, Clean Transition Tariff, at PDF page 6.

[101] PUCN, *Re: Application of Nevada Power Company, filed under Advice Letter No. 547, to implement Clean Transition Tariff Schedule No. CTT*, Clean Transition Tariff, at PDF page 6.

[102] Johnson, Anna, et al., *Industrial Rate Impacts on Electrification Projects in Illinois and Michigan,* ACEEE, February 5, 2026, at 19 and 21, available at https://www.aceee.org/sites/default/files/pdfs/industrial_rate_impacts_on_electrification_projects_in_illinois_and_michigan.pdf.

Examples:

- (Canada) British Columbia's Hydro and Power Authority's (BC Hydro) Clean Industry and Innovation Rate (Rate Schedule 1894) and Fuel Switching Rate (Rate Schedule 1985 **(approved, expires March 2037)**: offer industrial customers a discounted transmission service rate, which is applied to energy charges (per kWh)[103] and billing demand charges (per kVA)[104] for a period of seven years (20% discount for the first five years, 13% in year six, and 7% in year seven).[105]
    - Clean Industry and Innovation Rate – available to new (1) clean industry customers (defined as a new customer plant "that uses a process to remove greenhouse gases from the atmosphere or produces a renewable or low-carbon fuel," such as the capture/storage of carbon dioxide, the production of hydrogen electrolysis, and the production of synthetic fuels from hydrogen, carbon dioxide, or biomass); and (2) innovation customers (defined as a data center with a contract demand greater than 10,000 kVA, annual energy consumption of at least 70 GWh/year, and is not involved in producing/exchanging cryptocurrency.)[106] BC Hydro set a 5,000 GWh participation cap for this rate, which, in August 2023, it announced has been reached.[107]
    - Switching Fuel Rate – meant to encourage existing and new industrial customers to transition from fossil fuels to electricity.[108] A customer must demonstrate that it had a

[103] BC Hydro, "Rate Schedule 1894 – Transmission Service – Clean B.C. Industrial Electrification Rate – Clean Industry and Innovation (Rate Schedule 1894)," at 2, available at https://www.bclaws.gov.bc.ca/civix/document/id/lc/bcgaz2/295_2020_Appendix1.

[104] BC Hydro, "Rate Schedule 1894," at 1, available at https://www.bclaws.gov.bc.ca/civix/document/id/lc/bcgaz2/295_2020_Appendix1.

[105] By Hydro, "Industrial electrification rates: Discounted rates to connect to BC Hydro's grid," available at https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/electrification-rates.html; Note: ACEEE calls these rates "the only industrial tariffs we are aware of specifically meant to support electrification," Johnson et al., *Industrial Rate Impacts on Electrification,* at 19.

[106] BC Hydro, "Rate Schedule 1894," at 2-3, available at https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/electrification-rates.html.

[107] BC Hydro, "Industrial electrification rates," available at https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/electrification-rates.html.

[108] BC Hydro, "Industrial electrification rates," available at https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/electrification-rates.html.

"viable alternative" to receive power from a hydrocarbon fuel and that switching entirely or partially to electricity will result in an increase of electric use of at least 20GWh/year.[109] If the customer plans to still partially receive power from a hydrocarbon fuel, then only the portion of its load that is electrified will be billed under this rate.[110] Ineligible projects include oil transportation pipelines, oil refineries, methanol production and natural gas liquefaction facilities.[111]

[109] BC Hydro, "Rate Schedule 1895 – Transmission Service – Clean B.C. Industrial Electrification Rate – Fuel Switching (Rate Schedule 1895)," at 8, available at https://www.bclaws.gov.bc.ca/civix/document/id/lc/bcgaz2/295_2020_Appendix2.

[110] BC Hydro, "Rate Schedule 1895," at 6, available at https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/electrification-rates.html.

[111] BC Hydro, "Rate Schedule 1895," at 1, available at https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/electrification-rates.html.