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07/07/26
08:00 AM
R2106017

Flexible Service Connections:
Advancing Affordable Electrification Through Efficient Distribution Grid Utilization

Rulemaking (R).21-06-017

Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future

Assigned Commissioner's Proposal

July 2026

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Executive Summary

In Track 3 of the Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future (R.21-06-017), the record is clear there is value in pursuing flexible connection solutions that can delay or avoid the need for distribution grid upgrades by increasing the utilization of existing infrastructure. [1] This applies to infrastructure for the Mainline circuits that supply large load customers and on the Lateral circuits that supply a majority of customers.[2] Recent technical advances have enabled Distributed Energy Resource (DER) use cases that are specific to both large and small customers. Compared to the costs of performing distribution upgrades, flexible connection solutions may be cheaper and could enable deferral or avoidance of upgrades. The vision for this proposal is to advance initiatives that use flexible connections to provide customers capacity in a manner that increases the utilization of exiting grid infrastructure and provides more affordable options that will benefit ratepayers.

This proposal focuses on grid reliability, operational flexibility, maximizing efficient use of existing distribution capacity, and reducing or deferring infrastructure capital investment, through:

- Enabling and scaling flexible service connections (FSC)[3] to the distribution grid with non-firm capacity in a manner that adapts to changing needs.
- Maintaining affordability for customers by safely and reliably increasing the utilization of existing infrastructure.

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[1] Cal Advocates December 19, 2025, opening comments on Assigned Commissioner Ruling at 1; Utility Consumers' Action Network (UCAN) April 3, 2026, All Party Workshop Report Comments at 2; Interstate Renewable Energy Council (IREC) April 3, 2026, All Party Workshop Report Comments at 1; California Community Choice Association (CalCCA) December 19, 2025, opening comments on Assigned Commissioner Ruling at 3.

[2] Mainline circuits are large capacity, well modeled circuits that serve large customers and Lateral circuits tap off the Mainline to provide smaller capacity service to the majority of customers. Further detail on these circuit classes is provided in Section 3.

[3] As defined in the November 2025 ALJ and Assigned Commissioner Ruling, Flexible Connection is defined as a means of connecting a customer to a utility's distribution system under specific capacity limits that vary over time. Flexible Service Connection is a Flexible Connection provided for the purpose of serving customer load. Flexible Generation Connection is a Flexible Connection provided for the purpose of serving customer generation.

- Building utility capability in managing centralized and Grid Edge non-firm import capacity as a foundation to enable more advanced use cases in the future involving DER orchestration and DER grid services.

The Smart Inverter Operationalization Working Group (SIOWG) identified high priority use cases, all of which focus on the ability of a power system to respond reliably and safely to changes in electricity demand and generation.[4] Early implementation of solutions that utilize Power Control Systems (PCS) were detailed in the large Investor Owned Utilities' (IOUs)—Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E)—Bridging Solutions Reports[2] and responses to the November 2025 Assigned Commissioner's Ruling (ACR). Party comment on the SIOWG report, ACR, and on the Track 3 All-Party Workshop Report support the use of PCS as solutions that are appropriate and safe to help implement technology roadmaps and Commission directives related to Distributed Energy Resource Management Systems (DERMS) and Smart Inverter Operationalization.

The safe use of PCS to support operational limits and flexible connections is enabled by technology and standards[5] that have matured over the last five years. These technologies are currently used in both pilots and operational tools that address specific use cases for primary distribution system constraints on both the Mainline[4] circuits that supply large load customers and on the Lateral circuits that supply most customers. Real world results[6] have shown PCS-based solutions (e.g., operational limits and flexible connections) to be an effective tool for meeting customer needs, both when waiting for a capacity upgrade and as an alternative to an upgrade.

As flexible service connections have the potential for expanded use across a range of customer types and beyond solely as a bridging solution, they are the focus of this proposal. In addition to the flexible service connection solutions used to address primary distribution

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[4] Smart Inverter Operationalization Working Group Report, Attachment 1 to June 3, 2024 Administrative Law Judge Ruling at iii.

[5] E.g., Underwriters Laboratories (UL) 1741 Certification Requirement Decision for PCS, UL 3141 Standard for PCS.

[6] PCS based solutions have been used in PG&E's Flex Connect and Load Limit Letter offerings, and SCE's Load Control Management System.

grid constraints, which are supported by utility DERMS system and analysis tools, this proposal intends to offer recommendations for solutions that utilize the analysis routinely conducted in the engineering process when evaluating whether a mitigation or upgrade is needed and solutions that use Grid Edge DERMS to address secondary or site constraints.

The Commission has already recognized the value of flexible service arrangements through the Energization proceeding's (R.24-01-018) Decision (D.) 26-02-025. PG&E and SCE were directed to develop Standard Offer frameworks that allow customers to receive service through flexible operating arrangements while awaiting completion of planned distribution upgrades. The decision established a pathway for customers to voluntarily accept temporary capacity limitations in exchange for earlier access to electrical service and recognized that modern control technologies can safely provide customer capacity in circumstances where traditional infrastructure solutions could not be completed within requested customer timelines.

The Energization proceeding remains focused primarily on temporary or "bridging" solutions that enable customers to receive service while needed infrastructure upgrades to provide service are designed, permitted, and constructed. Ongoing activities include refinement of Standard Offer frameworks, evaluation of utility implementation plans, consideration of customer protections, communications requirements, and operational practices necessary to support flexible service during the upgrade period. These efforts are intended to improve customer access to capacity and reduce energization delays, particularly for customers whose operations would otherwise be impaired by infrastructure constraints. This proposal complements that work by examining circumstances where flexible service connections may provide value beyond the period traditionally associated with energization delays. While the Energization proceeding focuses on temporary flexible service as a bridge addressing timeline issues, this proposal builds on that foundation and other existing IOU offerings to address affordability issues by using flexible service connections as tools to defer or avoid those upgrades along with the associated ratepayer costs for a longer period of time and potentially permanently.

Flexible service connections represent a practical tool to address one of California's central energy policy challenges: accommodating significant load growth while moderating the distribution infrastructure upgrade costs that ultimately appear in customer rates. These solutions can provide benefits to both the IOUs and the capacity constrained customer while having a lower cost impact on ratepayers compared to the standard practice of addressing capacity constraints by immediately replacing capital equipment with extensive expansion of infrastructure. While the magnitude varies by outcome, there are benefits that can be realized if the upgrade occurs on the original schedule, the upgrade is deferred to a later date, or the upgrade is entirely avoided. This proposal will explore solutions that can demonstrate measurable customer and ratepayer benefits through avoided infrastructure costs, reduced interconnection expenses, and more efficient use of existing distribution facilities. This proposal discusses relevant practices and considerations, recommends implementation priorities, and identifies opportunities to reduce customer costs.

This proposal includes recommendations for Commission action related to advancing flexible connections. These recommendations and the associated proposed Advice Letters (ALs) and implementation actions are summarized below:

- Direct SDG&E to establish a Standard Offer, similar to the one established for SCE and PG&E via D.26-02-025. Implemented through a Tier 2 AL within 120 days of the Track 3 decision (Tier 2 FSC Implementation AL).
- Direct IOUs to record and provide values helpful to dedicated infrastructure customers independently implementing Operating Limits. Implemented through the Tier 2 FSC Implementation AL.
- Direct IOUs to make modifications to Electric Rule 2 to update definition of Controlled Load and add alignment language between the large IOUs. Implemented through the Tier 2 FSC Implementation AL within 120 days of the Track 3 decision).[7]
- Direct IOUs that before a ratepayer funded distribution upgrade associated with a customer, each IOU must evaluate whether a Limited Operating arrangement, Operating Envelope or other flexible connection mitigation enabled by PCS can

[7] Definitions should be consistent with those adopted through D.26-02-025.

safely satisfy the customer's requested capacity. Implemented through the Tier 2 FSC Implementation AL.

- Direct IOUs to provide Operating Limits as the default mitigation for distribution transformer upgrades, using certified UL 3141 devices. Implemented through the Tier 2 FSC Implementation AL.
- Direct for SCE and SDG&E to implement Variable Operating Envelope bridging solutions modeled after PG&E's Flex Connect. Implemented through a Tier 2 AL within one year of a Track 3 decision (Tier 2 Flex Connect AL).
- Direct the large IOUs host a workshop to further the discussion on Dynamic Operating Envelope to address abnormal grid conditions, and submit a workshop report within one year of a Track 3 decision
- Direct SCE and SDG&E to implement and scale Grid Edge DERMS for residential EV charging, similar to PG&E's ChargeBoost program and direct PG&E to expand and scale this pilot. Implemented through a Tier 2 AL (Tier 2 Grid Edge DERMS AL).
- Direct Energy Division staff-led workshops to further develop Grid Edge DERMS solutions. Workshops to discuss issues of capacity sharing, application authoring and program access, whether AMI meters are the appropriate long-term solution for computing the Operating Envelope, and ensuring that more devices than EV chargers can be locally controlled. Staff workshop reports would be filed to a successor Rulemaking.
- Direct a workshop, workshop report, and filing for IOUs to implement cybersecurity considerations from SIOWG. Implemented through a Tier 2 AL (Tier 2 Cybersecurity Implementation AL).
- Direct SCE and PG&E to offer non-bridging versions of current bridging offerings. Implemented through the Tier 2 Non-Bridging Solutions AL.
- Clarify that current Static and Variable Operating Envelope customers can elect to transition from a bridging to a persistent non-bridging solution, and direct IOUs to implement this via the Tier 2 FSC Implementation AL.

- Direct PG&E to formalize its Flex Connect offering and expand its non-bridging Flex Connect generation option to load customers. Implemented through the Tier 2 Non-Bridging Solutions AL.
- Direct the large IOUs to implement a non-bridging version of the Standard Offer. Implemented through the Tier 2 Non-Bridging Solutions AL.
- Establish Energy Division staff-led workshop to discuss reasonable guardrails to ensure interoperability and customer choice. Implemented through a workshop report filed within a successor Rulemaking.
- Direct IOUs to default customers on a Variable or Dynamic Operating Envelope to a real-time pricing rate, and direct IOUs to track relevant data. Implemented through the Tier 2 FSC Implementation AL.

Section 1. Introduction

A central objective of this proposal for flexible service connection solutions is to support customer affordability. California faces increasing distribution system investment needs driven by high levels of DERs, transportation electrification, building electrification, and emerging large loads. Flexible connections offer an opportunity to provide customers with needed electric capacity more quickly and at a lower cost than traditional infrastructure upgrades in many circumstances. By increasing utilization of existing grid assets and deferring or avoiding capital investments where appropriate, these solutions can reduce upward pressure on rates while maintaining reliability and safety.

Flexible service connections can transform customer flexibility into a distribution planning resource, allowing the state to accommodate load growth while limiting the infrastructure buildout that is needed. California must plan for the anticipated increased load necessary to achieve its transportation and building electrification goals. Accommodating this load will require significant distribution investments and associated costs that ratepayers will likely pay. The magnitude of those investments is highly dependent on when and how customers use electricity. Managed and flexible load scenarios have the potential to materially reduce the need for these investments through increased grid utilization.

A two-part Electrification Impact Study (EIS) was conducted to evaluate the impacts of high levels of DER adoption on distribution grid infrastructure and costs.[8] The first part of the study (EIS Part 1) presents a granular bottom-up load forecasting methodology that provides information on where and when distribution grid enhancements and investment may be needed to support grid reliability. It also provides a preliminary estimate of the potential costs of meeting these needs for the large IOUs.[9] The second part of the study (EIS Part 2) estimates and evaluates the potential impacts of meeting electrification needs

[8] See D.24-10-030 Ordering Paragraphs 19-20

[9] EIS Part 1 Study: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K423/508423247.PDF

under multiple scenarios (base case, equity in DER adoption, and demand flexibility), including the associated costs of upgrading the primary and secondary distribution systems.[10]

The Public Advocates Office also conducted two Distribution Grid Electrification Model (DGEM) studies.[11] A major finding from the DGEM and EIS studies is that infrastructure costs are highly sensitive to load shapes and peak demand assumptions.[12] This means that distribution upgrade needs and costs are highly dependent on customer flexibility, not just customer load. Different assumptions regarding electric vehicle (EV) charging behavior and load management can result in dramatically different upgrade requirements and cost forecasts. This is where flexible connection offerings become valuable. Traditional service assumes customers always receive their requested peak capacity. Flexible service recognizes that:

- Distribution constraints are often limited to relatively few hours.[13]
- Some customers may be willing to accept operational limits during those periods, and the impact of these limits is often negligible or manageable through technological solutions.
- Managed charging, PCS, and storage can automatically reduce demand when needed.

As a result, flexible service arrangements can increase the utilization of existing distribution assets and reduce the need to build infrastructure where consistent, reliable demand flexibility can allow existing assets to serve customer needs. In the face of our current affordability challenges, findings that secondary upgrades are anticipated to make up the majority of distribution grid infrastructure costs[14] through 2040, and party comment

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[10] See PG&E, SCE and SDG&E Electrification Impact Study Part 2 Final Reports: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M596/K907/596907812.PDF; https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M596/K907/596907811.PDF; https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M596/K903/596903988.PDF

[11] Public Advocates Office Motion to Admit its DGEM Study into the record for R.21-06-017. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M591/K699/591699340.PDF

[12] Ibid, at 83.

[13] All-Party workshop discussions noted examples where the customer needs were met 95% or more of the time without upgrades, and utilities weren't sure the customer would even notice the difference provided by an upgrade.

[14] PG&E EIS Part 2 Final Report, Section 6.2.5 Sensitivity of Secondary Costs: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M596/K907/596907812.PDF

around the necessity to address secondary capacity issues,[15] we examine the feasibility of applying existing tools and processes to cases where secondary upgrades funded by ratepayers may be avoided through flexible connection.

This proposal recommends changes that would support modernization of the IOUs capacity evaluation practices. These recommendations are targeted at areas where conventional practices may result in unnecessary expense for ratepayers, foregone utility revenue from bringing new permanent load online that would historically have had to wait for an upgrade, and avoidable projects for the IOUs. Rather than addressing demand flexibility through near real-time provisioning of centralized commands, this proposal focuses on solutions that can operate through predefined operational limits, contractually obligated flexibility, and customer-side controls. These approaches can enable customers to receive service more quickly, increase utilization of existing distribution infrastructure, and reduce or defer infrastructure investments while maintaining safety and reliability.

By leveraging advances in PCS, smart inverter functionality, and flexible connection frameworks, utilities can provide capacity in a manner that better aligns infrastructure investments with actual system needs and customer usage patterns. These changes are recommended with two ends in mind. First, these changes could put downward pressure on rates through the additional revenue associated with higher infrastructure utilization, particularly where the cost of avoided infrastructure projects would have otherwise been the complete responsibility of ratepayers. Second, as these operational changes are incorporated into distribution planning processes, they are expected to reduce the number of projects needed and their related capital expense that is passed along to ratepayers.

This proposal is organized with the following sections:

- Section 2 discusses cases where potential for delay or deferral of ratepayer funded upgrade projects provides opportunities to reduce expenses for ratepayers and customers.

[15] UCAN Comments on All Party Workshop Report at 9 and IREC Comments on All Party Workshop Report at 7.

- Section 3 provides an overview of the relevant distribution infrastructure and discusses the current practices and programs used for matching capacity to forecasted customer need.
- Section 4 summarizes the types of Operating Envelopes and their requirements, as well as how the IOUs have used Operating Envelopes to deliver flexible connections.
- Section 5 outlines the relevant cybersecurity considerations.
- Section 6 discusses bridging and non-bridging flexible connection solutions, including ratepayer funding implications.
- Section 7 explores concerns voiced by parties around competition and access.
- Section 8 discusses the benefits and considerations of real-time pricing for flexible connection customers.
- Section 9 provides recommendations and proposed Commission actions.
- Appendix A provides a glossary of terms used.

Section 2. The Affordability Opportunity: Reducing Customer and Ratepayer Costs Through Flexible Capacity Solutions

The technologies necessary to enable flexible connections are mature and already deployed[16] within each utility territory at a limited scale. The need for, and the level of ratepayer cost due to distribution grid infrastructure projects depend on the IOU's forecast of the capacity that a customer site will need. In nearly all cases, ratepayers pay some portion of the cost associated with new connections and upgrades, either directly or through customer allowances.[17] Historically, this utility forecast assumed the most conservative case[18] as there was no standardized way to control the maximum capacity needed by the site. However, there are now operational IOU offerings that keep loads below the highest peak scenario and allow customers to take service without needing immediate upgrades. These tiers of capacity control are described in more detail in Section 4.

The record set forth in Track 3 of the High DER proceeding highlights broad agreement that flexible connection solutions can provide a cost-effective means of increasing utilization of existing distribution infrastructure while maintaining safe and reliable operation. Parties note that many distribution constraints are driven by infrequent peak conditions and that traditional planning approaches often require distribution infrastructure to be sized to accommodate maximum forecast demand even when that level of demand may occur only rarely. Recent advances in PCS, smart inverter functionality, operational limits, and DER controls provide utilities with new tools to manage these conditions and offer customers service alternatives that were not previously feasible. By leveraging these technologies, utilities can provide customers with access to needed capacity while reducing reliance on upgrades consisting of infrastructure replacement or addition as the default solution to capacity constraints.

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[16] D.26-02-025 Finding of Fact 32

[17] Addition of new and permanent load provides the customer with a cash allowance toward upgrade construction costs whose amount is a flat rate for residential customers and dependent upon projected energy usage for nonresidential customer.

[18] The most conservative case results from assuming all loads are operating at the highest peak demand forecasted by one of the three methods listed in the *Forecasting Customer Site Demand portion* of Section 3 without any demand flexibility or onsite generation.

The affordability benefits of flexible connections extend beyond those cases where an upgrade is completely avoided. When a flexible connection enables a customer to receive service for new and permanent load while an upgrade is deferred, ratepayers may benefit from increased revenue and the associated revenue requirement impacts. Customers can benefit from earlier energization and reduced waiting times, while utilities can benefit from additional flexibility in planning and sequencing infrastructure investments. Even in circumstances where an upgrade ultimately proceeds on its original schedule, the ability to utilize existing infrastructure more efficiently can reduce the amount of infrastructure that must be installed, improve asset utilization, and provide valuable operational experience with technologies that will be increasingly necessary to support California's electrification goals and the proliferation of DERs. Thus, flexible connection solutions should be viewed not just as alternatives to infrastructure upgrades, but also as tools that improve affordability by aligning distribution system investments more closely with actual customer needs and system conditions.

The Public Advocates Office's DGEM and the IOUs' EIS studies both illustrate that future distribution system costs are highly dependent on customer flexibility and load management. This proposal focuses on how to provide practical mechanisms for incorporating customer flexibility into the provision of service and providing the Large IOUs with the direction that allows them to use it as a distribution planning resource, thereby reducing upward pressure on customer rates while supporting electrification and load growth.

Section 3. Distribution Capacity Determination: Existing Infrastructure, Forecasting Practices, and Capacity Evaluation Methods

This section provides a foundation for why a flexible connection solution that works for one particular customer or use case may not work for others. There are different flexible solutions tailored to specific use cases where the level of modeling and deployed options are commensurate with the class of medium voltage[19] connection they utilize on the primary distribution grid. Flexible solutions also vary based on whether the secondary transformer fed by that primary connection is dedicated to one customer or whether its capacity is shared among several customers.

Distribution Grid Infrastructure Classes—Mainline and Lateral Primary Distribution Grid

To clearly discuss the appropriate flexible connection options, rather than focusing on a "polyphase grid,"[20] this proposal discusses the primary distribution grid as two classes of circuit according to their level of modeling and deployed offerings—Mainline and Lateral. While both Mainline and Lateral are at primary voltage (e.g., 21 kV), the difference is the wire size, or ampacity, and the number of phases.

Mainline refers to those portions of the primary distribution grid that directly convey power from substations through large three phase conductors to the service transformers which serve most of the system demand. Mainline primaries are subdivided into circuits and segments and are routinely modeled in power flow software. The IOU Uniform Load Integration Capacity Analysis (Load ICA) and Uniform Generation Integration Capacity Analysis (Generation ICA) provide hourly capacity data for Mainline primary distribution grid customers.

Mainline primary distribution customers are served without the use of smaller medium voltage primary lateral conductors. Most customers on the Mainline take polyphase service, either through dedicated service transformers or shared secondary transformers.

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[19] ANSI C84.1 defines voltage classes as Low (≤1,000V), Medium (1 kV–100 kV), High Voltage (100 kV–230 kV), Extra High Voltage (231 kV –1,000 kV), and Ultra High Voltage (>1,000 kV).

[20] As defined in the November 3, 2025 ACR at 6

Lateral refers to those portions of the primary distribution grid that are fed from the Mainline through smaller conductors and serve most distribution customers. The ICAs show these portions and assign them a unique identifier but most of these lines are not modeled in power flow software and do not have publicly available hourly capacity data. Most customers served by a Lateral primary receive single phase service over shared secondary conductors after voltages are further stepped down through a distribution transformer.

As an informal guideline, Mainline customers can access hourly data through IOU capacity maps and Lateral customers cannot access hourly capacity data on those large IOU maps.

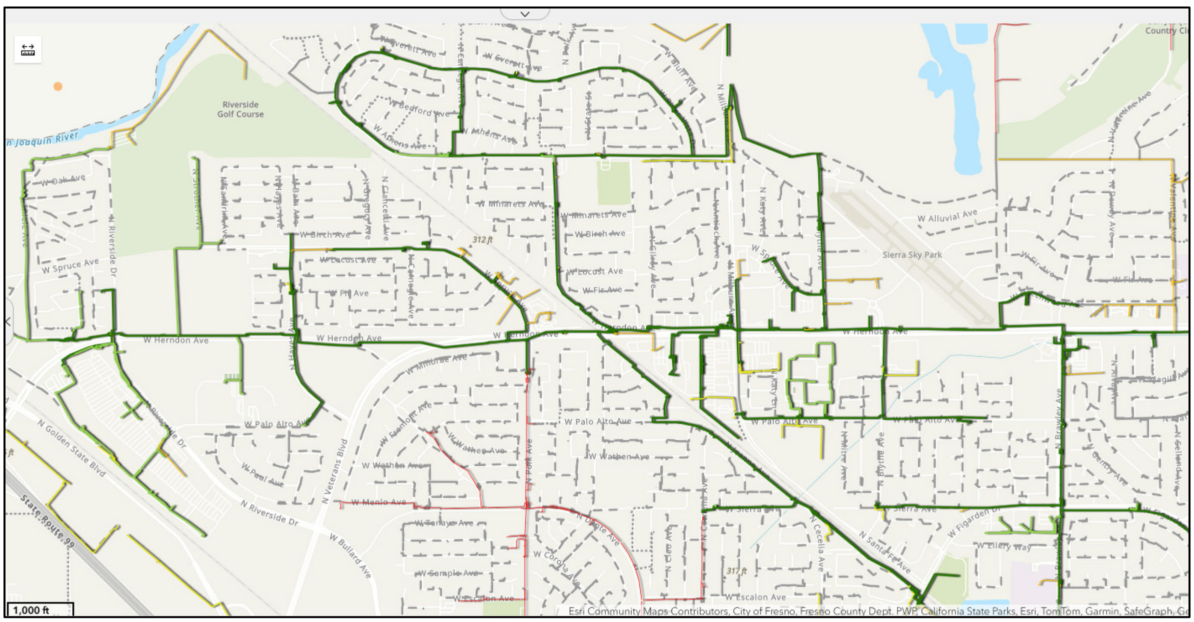

Figure 1: North Fresno Map[10]

The Mainline primaries are shown in Figure 1 in colored lines, and the Lateral primaries are represented by the grey lines. Most of the Lateral primaries are single phase, shown as dashed grey lines, with some two-phase Lateral primaries indicated by dotted grey lines, and few three phase Lateral primaries indicated by solid grey lines (e.g., shown in Figure 1 above and to the right of the golf course).

Primary and Secondary Conductors

Power moves efficiently over much longer distances at medium or higher voltages than it does at low voltage. Substations host step-down transformers; high voltage from the transmission system is stepped down to medium voltage. The IOU primary conductors operate at this medium voltage; this is the primary side of the distribution system. Generally, the difference between power capacity of the medium voltage conductors used for a Mainline primary and the power capacity of conductors used for a Lateral primary operating at the same voltage is about an order of magnitude.[21]

Most customers take service at low voltage and are served on the secondary distribution system. The secondary distribution system is provided by using a utility owned transformer to convert primary system voltage[22] to the lower secondary system voltage[23]—this transformer is called a distribution transformer. Following the voltage step down, power is delivered to customers through a service line which connects to the customer premise. Circuits may also contain additional distribution secondary lines between the distribution transformer and the service line; in some cases, an additional transformer—called a service transformer—placed before the service line may be needed to again lower voltage before reaching the customer premise. While several customers can share a distribution transformer,[24] the distance between those customers is generally within a thousand feet to avoid unacceptable voltage drops.

Based on the presentation from PG&E at the All-Party Meeting[25] and associated discussion, it is clear that the secondary conductor's capacity is often less than a customer's service entrance capacity and not readily known to either the IOU or customer. This creates challenges for those secondary customers seeking service or interested in a flexible connection.

Forecasting Customer Site Demand

To connect a customer to the distribution grid, the IOU first must determine what their capacity needs are and then determine that there is enough grid capacity at their

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[21] EPRI 1000419 at Table B-1 discusses typical sizing of Mainline and Lateral conductors. The disparity in between Mainline and Lateral capacity is due to a couple of factors: 1)Mainline primaries have 3 phases and provide service with three phases while Lateral primaries generally provide service on one phase, even if several phases are present in the circuit and 2) the Large Load primaries are roughly 5 times (350 kcmil vs. #2 wires) bigger wires than the Majority Customer equivalents.

[22] PG&E Electric Rule 2 at 2 states that primary voltages include 2,400, 4,160, 6,930, 12,000, 17,200, and 20,780 volts.

[23] PG&E Electric Rule 2 at 2 states that secondary voltages include 120, 208, 240, 277, and 480 volts.

[24] Low voltage conductors serving multiple customers are known as shared secondary.

[25] All-Party Workshop report at 61-64

location to serve those needs. The Joint IOU Standard Offering AL (Joint SO) (PG&E AL 7868-E and SCE AL 5790-E) articulates three conventional methods PG&E and SCE use for estimating a customer's demand load.[26] These include: (1) historical demand of similar customers, (2) demand per square foot by type of occupancy, and (3) customer plans and operational needs.[27] For each of these methods, the forecasts rely upon representative load curves that give the shape of the hourly load, based upon rigorous statistical analysis of data from actual customer sites and adjusted based on peer reviewed models. [28] These load curves have been a reliable way of forecasting the power used by a site at any given time, as that energy can be predicted by facility type and size, as well as outside temperature.[29] The IOUs do not make demand load values available to the customer and it is unclear whether they are retained once a customer is provided service.

Historically, utilities have assumed customers require continuous access to their maximum forecast demand, meaning the most conservative or highest peak condition is used when evaluating infrastructure needs. However, advances in PCS, energy storage, and Operating Envelope frameworks now allow customer demand and generation to be managed during the limited periods that drive distribution system capacity requirements. As a result, customer flexibility can increasingly be incorporated into capacity evaluations, reducing the need to build infrastructure sized solely for infrequent peak conditions.

Forecasting Grid Capacity

The way grid capacity is forecasted varies between Mainline primary and Lateral primary locations.

Mainline Primary Capacity Forecast Using Power Flow Models

The grid that is comprised of Mainline primary conductors, along with their protection and regulation devices, is modeled within power flow software. This software is used to understand how the different components interact with each other over time,

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[26] Demand load is defined as: "the expected coincident load imposed on the system", Joint SO Advice Letter (PG&E Advice Letter 7868-E and SCE Advice Letter 5790-E) at 4.

[27] Joint SO Advice Letter at 4-5.

[28] Examples of these models include those generated by the NREL/LBNL End Use Load Profiles, the EPRI Load Shape Library, and the PG&E Load Shape Viewer

[29] PG&E EPIC 2.23 final report at 12.

capturing not only capacity but whether the customer's use of that capacity will result in thermal, voltage, or reactive power exceedances. These models support the IOUs' ICA tools.

Lateral Primary Capacity Forecast using AMI Data Aggregation

Unlike Mainline primary facilities, Lateral primary facilities are generally not represented in detailed power flow models used for distribution planning and hosting capacity analysis. Instead, the large IOUs increasingly rely on Advanced Metering Infrastructure (AMI) data and Advanced Distribution Management System (ADMS) capabilities to estimate loading on secondary transformers and Lateral primary facilities. Through these systems, customer interval usage data can be associated with the distribution assets serving those customers and aggregated to estimate historical loading and forecast future capacity needs.

As part of ongoing grid modernization efforts, each of the large IOUs has integrated AMI data into its operational and planning systems to improve visibility into distribution system loading below the Mainline level.[30] This capability allows them to move beyond traditional nameplate assumptions and incorporate actual customer usage patterns when evaluating capacity constraints. During Track 3 workshop discussions and comments on the workshop report, the IOUs described varying levels of deployment of these capabilities. Notably, SDG&E stated that AMI interval data is aggregated at the distribution transformer level within its ADMS environment, enabling operational visibility into transformer loading.[31] The other IOUs are readying similar initiatives as they continue integrating AMI, DERMS, and ADMS platforms to improve situational awareness and forecasting accuracy.[32]

Because Lateral primary, as well as secondary system, capacity evaluations are increasingly informed by measured customer load data rather than solely by engineering assumptions, these locations present a significant opportunity for the application of flexible connection solutions. Where actual customer demand differs materially from nameplate ratings or the most conservative planning assumptions, IOUs may be able to safely provide

[30] PG&E November 25, 2025 response to November 3, 2025 ACR at 11; SCE April 19, 2024 Grid Modernization Progress Report at 8;

[31] SDG&E January 2, 2026 response to November 3, 2025 ACR at 3.

[32] SDG&E November 25, 2025 response to November 3, 2025 ACR at 7

additional customer capacity through flexible connection approaches such as Operational Limits or Operating Envelopes while also increasing utilization of existing infrastructure.

For these reasons, the recommendations discussed later in this proposal focus on advancing flexible connection solutions for Lateral primary and secondary system use cases through Operating Limits and Grid Edge DERMs.

Forecast Limitations

While the forecasts continue to predict the amount of power that a site will need to meet its load at a given time, the addition of onsite storage and EVs at some customer premises means that those forecasts do not necessarily predict the load that the distribution grid will see. There is no single factor that predicts the charging and discharging behavior of stationary battery storage, thermal energy storage, or EVs. While IOUs can reasonably predict the aggregate impact of DERs at the Mainline level,[33] we are not aware of any Commission or State-adopted methodology to predict the demand load impact of the addition of storage-based DER systems (e.g., batteries, EVs, electric water heaters). This necessitates additional flexible service options to support forecasting and appropriately serving the needs of these customers while reducing cost impacts on ratepayers.

When Capacity is Deemed Insufficient - Mitigation or Upgrade

When distribution grid capacity is deemed insufficient, the measures taken to remedy the capacity shortfall can be categorized as either low-cost mitigations or grid upgrades.

Mitigations, sometimes referred to as "no-to-low-cost mitigations," are characterized[34] by being minor in nature, historically performed within months, and expected to cost in the range of thousands to tens of thousands of dollars, falling into maintenance functions for the purposes of general rate case classification. Examples of mitigations include reconfiguring circuits, installing or relocating voltage regulation equipment, adjusting existing equipment settings, enabling capacitor banks, or using smart inverter volt/var and volt/watt capabilities.[35] Grid upgrades, in contrast, require significant

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[33] PG&E EPIC 2.23 final report, *passim*.
[34] Resolution E-5296 at 36-37.
[35] Resolution E-5296 at 41.

design and procurement, several months to years to implement, and hundreds of thousands to millions of dollars to implement. Examples of grid upgrades include primary line reconductoring, front of the meter storage, substation transformer replacement, and protective equipment replacement.[36] The goal of this proposal is to reduce ratepayer spending on grid upgrades while ensuring safety and reliability that allows energization for customers in a timely manner.

[36] Resolution E-5296 at 41-42.

Section 4. Operating Envelopes and Dynamic Capacity Management

Tiers of Capacity Control

Currently available and mature flexible connections[37] allow for five different tiers of capacity control, differentiated by temporal granularity. Limited Power, Static Operating Envelopes, Variable Operating Envelopes, and Dynamic Operating Envelopes represent a continuum of increasing operational sophistication that enables progressively greater utilization of distribution infrastructure and greater technological requirements to unlock capacity while maintaining safe and reliable operation. These tiers are summarized in Figure 2 below.

Figure 2: Characteristics and Requirements of Flexible Connection Tiers

Tier of Capacity Control	Source and Frequency of Directed Non-Firm Capacity	Communication Requirements	Level of Required Customer Flexibility
Limited Power	None (firm)	None	Low, fixed setpoint
Static Operating Envelope	None (firm)	None	Low, fixed envelope
Variable Operating Envelope	Forecast-based, directed at approx. daily frequency	Moderate	Moderate, day-ahead envelope
Dynamic Operating Envelope	Utility Enterprise DERMS based, directed based on emergent circumstances	Near real-time	High, near real-time envelope
Grid Edge Dynamic Operating Envelope	Autonomous sensing from AMI, locally refreshed every 15 minutes or less	Very high – communication between contiguous infrastructure and site load/storage	High, near real-time envelope

This section describes these tiers of flexibility, gives examples of how they currently operate, describes the levels of technology needed for deployment, and lists the IOU offerings that use or pilot these technologies. The current offerings primarily focus on limiting large customers to avoid constraints on Mainline primary[6] or substation

[37] This consists of non-tariffed IOU pilots, CPUC authorized pilots via tariffs or via EPIC, and other operational tools the IOUs use for customers.

infrastructure with the exception of Grid Edge Dynamic Operating Envelopes which primarily focus on limiting small loads to avoid constraints on secondary transformers and conductors.

As utilities develop enhanced visibility, forecasting, and control capabilities, Operating Envelopes can evolve from fixed planning limits toward dynamic operational limits that more closely reflect actual grid conditions in near real-time. This proposal aims to expand the IOU offerings for these different Operating Envelopes.

Limited Power Used to Address Secondary Constraints

Limited Power provides a flexible connection solution using a single unchanging operating limit rather than the schedule of values that make up an Operating Envelope. While Limited Power is technically a single value subset of Static Operating Envelope, for purposes of this proposal it is broken out separately. This is in part because Static Operating Envelopes are designed to serve Mainline customers yet Limited Power could be more widely scaled.

As an example of Limited Power, if an electric school bus depot has 10 busses that charge at 48 amperes (A) but only 400 A of capacity, they could set their PCS to restrict demand to under 400 A and charge up to eight buses at a time (48 A x 8 buses=384 A) in lieu of onsite construction (e.g., trenching through their parking lot) and utility side upgrades. Under this approach, customer imports or exports are continuously constrained to a fixed value established during the engineering portion of the service planning or interconnection initial review process. There is no ongoing communication of operating limits and no expectation that available capacity will vary over time, unlike Variable or Dynamic Operating Envelopes. The customer is instead responsible for ensuring that site operations perpetually remain within a single approved setpoint. Because the approved operating limit remains unchanged throughout the year, Limited Power can be viewed as a simple approach to flexible service that minimizes operational complexity while still enabling utilization of available capacity that would otherwise remain inaccessible under conventional planning assumptions.

This approach can provide value for customers seeking modest increases in import or export capability where more complex Operating Envelope solutions are unavailable (e.g., due to a lack of existing power flow models for Static Operating Envelopes) or infeasible (e.g., due to the cost of communications equipment for Variable Operating Envelopes). For example, a manufacturing facility or EV charging depot seeking to expand operations may be able to receive service under a Limited Power arrangement even when additional firm capacity is unavailable. Similarly, customers seeking to interconnect distributed generation may be able to utilize Limited Export arrangements in lieu of ratepayer funded[38] secondary or Lateral primary upgrades.

Existing examples include Rule 2 and 3 energization pathways[39] for customers located on dedicated secondary facilities, as well as Limited Export interconnection pathways that utilize fixed export controls to maintain exports below specified thresholds, such as 15 percent of line section peak load. In each case, the IOU's planning and operational assumptions are honored by ensuring that customer imports or exports cannot exceed the approved limit.

Among the flexible connection tiers discussed in this proposal, Limited Power has the lowest implementation requirements. It requires only a certified control device capable of monitoring site load or generation and automatically controlling equipment to maintain operation below a single approved setpoint. This can easily be accomplished by the installation of a UL 3141 certified PCS. Unlike Variable or Dynamic Operating Envelopes, no utility communications channel, DERMS integration, interoperability testing, or real-time operational coordination is required. As a result, Limited Power represents a low-cost and readily deployable flexible connection solution that can increase utilization of existing distribution infrastructure while providing customers with an alternative to costly and potentially unnecessary infrastructure upgrades.[40]

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[38] Upgrades necessitated by NEM or NBT generation under 1 megawatt are funded by ratepayers.
[39] D.26-02-025 Ordering Paragraph 2
[40] D.26-02-025 Finding of Fact 32.

Static Operating Envelope Used to Address Mainline Primary Constraints

A Static Operating Envelope establishes a schedule of fixed import or export operating limits for a customer, group of customers, or DER based on engineering analysis of distribution system constraints. D.26-02-025 in the Energization Rulemaking established the Standard Offer for SCE and PG&E which is a Static Operating Envelope. This schedule of limit is predetermined and remains unchanged over time unless modified through a subsequent utility review. The limits within the schedule are selected to ensure that operation within the envelope does not result in violations of applicable thermal, voltage, protection, or power quality criteria under the range of conditions considered during the engineering evaluation. One example of this is a large commercial or industrial customer (e.g., a factory or charging depot) that can shift their work or charging hours to move peak demand to an earlier period.

As mentioned in the previous subsection , Limited Power is technically a type of Static Operating Envelope. Thus, there are two tiers of capacity control within Static Operating Envelopes--a Static Operating Envelope with a single value that does not change over time is known as an operational limit, and a mix of operational limits[41] and envelopes that comprise a schedule of values that change over time. This latter tier represents most utility offerings to date.

Large IOU Static Operating Envelope offerings that utilize schedules of values are used to address Mainline primary Constraints in part due to the ease with which a schedule of values can be generated from existing power flow models. Additionally, the large IOUs use Static Operating Envelopes informally[42] to allow both Mainline and Lateral primary generation customers to receive conditional Permission to Operate.[43]

Static Operating Envelopes are best used in locations where constraints are well understood, relatively infrequent, or can be addressed through conservative operating limits.

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[41] Formal Static Operating Envelope offerings using Operational Limits are the PG&E's Load Limit Letters and the Standard Offer from PG&E and SCE. Informally, Large IOUs address secondary constraints by granting conditional permission to operate through the use of Limited Power.

[42] For generating facilities, this is offered under mutual agreement provisions in Electric Rule 21.

[43] PTO is the express written permission granted allowing a generator to commence operation in parallel with the distribution grid, as set out in Electric Rule 21 Section D.1.

As a result, they can provide a low-cost and readily deployable means of increasing utilization of existing distribution infrastructure and supporting flexible connection solutions without requiring advanced utility operational systems or customer participation in real-time control schemes.

Variable Operating Envelope used to Address Mainline Primary Constraints

A Variable Operating Envelope expands upon a Static Operating Envelope by introducing a non-firm capacity component in addition to a fixed level of firm capacity. The firm capacity portion is a Static Operating Envelope, comprising a constant schedule that is always available to the customer. The non-firm capacity portion is additional capacity on top of the firm capacity; non-firm capacity is not guaranteed to be available but could be available based on forecasted grid conditions. When additional capacity is available, it is communicated to the customer and scheduled for operation at least one day in advance through a change in the customer's non-firm schedule. Once communicated and scheduled, the non-firm capacity associated with a Variable Operating Envelope is expected to remain available and would only be modified in response to defined circumstances, such as abnormal system conditions, equipment outages, contingency operations, or other events consistent with Electric Rule 11 and 14 provisions. In the case of communications loss, the PCS should default to limiting the customer to the firm capacity guaranteed and described by the underlying Static Operating Envelope.

The firm and non-firm capacity structure can provide substantial customer value while reducing the need for immediate infrastructure upgrades. For example, a manufacturing facility, data center, EV charging depot, or research facility may require capacity above the firm capacity available at a location but may be willing to accept that firm capacity in conjunction with available non-firm capacity in exchange for earlier energization. In order to operate as planned under the firm capacity immediately available, customers must be capable of flexible operations, for example through leveraging behind-the-meter vehicle charging or discharging onsite storage. During periods when non-firm capacity is available customers, for example those with high power EV charging or industries that can ramp up energy consumption, may charge vehicle batteries or operate without restrictions. If the utility temporarily withdraws a portion of the non-firm capacity, the customer can discharge stored energy or modify operations to remain within the firm capacity allocation. In this way, customers may obtain access to additional capacity and operational flexibility without waiting for distribution upgrades to be completed.

The IOUs are already exploring and implementing examples of this approach. PG&E's SAVE pilot[44] and Flex Connect operational tool[45] utilize utility-managed operating limits to provide customers with access to capacity that may not otherwise be available under conventional interconnection and energization practices. Similarly, SDG&E's Wholesale Distribution Access Tariff (WDAT)[46] As-Available Capacity Pilot explores providing customers access to capacity that exists under most operating conditions but cannot be guaranteed on a fully firm basis.

Unlike Static Operating Envelopes, Variable Operating Envelopes are not "set-and-forget" solutions. Implementation requires the utility to communicate operating limits to customer equipment and verify that the customer is respecting those limits. As a result, Variable Operating Envelopes require deployment of certified customer-side equipment that has successfully completed interoperability testing with the utility's Enterprise DERMS platform or other approved operational systems. They also require the provisioning and maintenance of a secure communications[47] channel capable of transmitting operating instructions, as well as customer equipment capable of automatically modifying site operations in response to the IOU provided daily non-firm capacity schedules. These requirements represent an intermediate level of operational sophistication that provides greater utilization of existing distribution infrastructure than a Static Operating Envelope while avoiding much of the complexity and high-speed communications infrastructure that Enterprise DERMS Dynamic Operating Envelopes require.

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[44] https://investor.pgecorp.com/news-events/press-releases/press-release-details/2025/PGE-Launches-Seasonal-Aggregation-of-Versatile-Energy-SAVE-Virtual-Power-Plant-Program/default.aspx

[45] https://investor.pgecorp.com/news-events/press-releases/press-release-details/2025/New-PGE-Service-Offering-Makes-It-Easier-and-Faster-to-Connect-EV-Chargers-EV-Fleets-and-Big-Batteries-to-the-Grid/default.aspx

[46] https://www.sdge.com/more-information/customer-generation/wholesale-generator-transmission-interconnections

[47] A secure communications channel can be provided over public internet using firewalls, whitelisted IPv6 addresses, and encrypted communications.

This greater utilization enabled by centralized provisioning of Variable Operating Envelopes comes at the cost of requiring the IOU to provide Enterprise DERMS systems, robust power flow models, and communications and interoperability infrastructure. The corresponding customer costs run in the tens of thousands of dollars and may result in Variable Operating Envelopes only being used to address Mainline primary and by larger, sophisticated customers of large IOUs with Enterprise DERMS systems.

Feasibility of Using Variable Operating Envelope to Address Secondary Constraints

The principles underlying Variable Operating Envelopes could also be applied to secondary distribution infrastructure, including service transformers and secondary conductors. Unlike Mainline constraints, which are typically evaluated at the feeder or primary distribution level, secondary constraints often affect a small group of customers that are electrically connected to the same distribution asset. These customers are considered electrically contiguous because their imports and exports collectively impact the loading of a shared distribution transformer, secondary conductor, or other secondary distribution facility.

Offering Variable Operating Envelopes as a mitigation for Lateral primary or secondary constraints, though, addresses a larger number of customers than offering them to address Mainline primary constraints and thus will require a less computationally intensive method for generating the firm and non-firm schedule of values as compared to the Mainline. Historically, utilities have evaluated new load and generation requests independently, often requiring upgrades when aggregate customer activity could exceed equipment ratings under worst-case assumptions. However, advances in AMI data aggregation, PCS, and customer-side energy management technologies create opportunities to evaluate and manage these customers as a coordinated group. For this reason, this proposal aims to expand Variable Operating Envelope offerings to the secondary system.

Dynamic Operating Envelope used to Address Mainline Primary Constraints

A Dynamic Operating Envelope represents the most advanced form of flexible connection. Unlike a Static Operating Envelope, which establishes fixed schedules or operating limits, or a Variable Operating Envelope, which provides a fixed firm capacity accompanied by a non-firm capacity allocation that is modified only under limited circumstances, a Dynamic Operating Envelope continuously adjusts the available non-firm import or export capacity based on actual and near real-time forecast distribution system conditions. Under a Dynamic Operating Envelope, customers receive a schedule of available capacity that may change throughout the day as system and/or local conditions evolve. In the case of communications loss, the PCS should default to limiting the customer to the firm capacity guaranteed and described by the underlying Static Operating Envelope.

The non-firm operating limit is recalculated by Enterprise DERMS, at least hourly but potentially every five to fifteen minutes, using information from rapidly updated readings of actual grid conditions. While a baseline level of non-firm capacity can be expected based on forecast conditions, it is not guaranteed under a Dynamic Operating Envelope. This approach enables greater utilization of existing distribution infrastructure because capacity is allocated according to actual system abilities rather than the most conservative planning assumptions or necessarily conservative forecasts. While the IOUs do not currently offer Dynamic Operating Envelopes to large load customers, PG&E has demonstrated the underlying technology through its Flex Connect program, potentially providing a mechanism for directing DERs during emergent system conditions or for maximizing customer access to available capacity.

The benefits of a Dynamic Operating Envelope come with significant operational and technical requirements. A customer seeking to utilize a Dynamic Operating Envelope would typically require a high degree of operational flexibility. For example, a manufacturing facility, data center, or EV charging depot could receive substantially more capacity than would otherwise[48] be available at a constrained location but may need the ability to rapidly modify operations or utilize substantial stored energy to take advantage of additional non-firm capacity or function during periods without it. Implementation requires certified customer equipment that has successfully completed interoperability testing with the utility's Enterprise DERMS platform, continuous maintenance of a secure high-speed

[48] As compared to a Static Operating Envelope or a Variable Operating Envelope.

communications connection, and automated controls capable of responding to frequent changes in operating limits.

Dynamic Operating Envelopes are not "set-and-forget" solutions; they depend upon ongoing coordination between utility operational systems and customer equipment. The operational burden associated with maintaining near real-time communications, monitoring system conditions, and issuing operating instructions also creates scalability challenges for utility Enterprise DERMS platforms. As noted in IOU responses[49] and demonstrations,[50] Enterprise DERMS solutions may be best suited for managing a relatively limited number of large and operationally significant resources rather than serving as the primary control mechanism for very large populations of flexible connection customers.

For these reasons, this proposal does not focus on scaling Dynamic Operating Envelopes that leverage Enterprise DERMS but recommends allowing IOUs a pathway to propose development of an Enterprise DERMS-based Dynamic Operating Envelope if they choose. Given the computational and resource intensity of this approach to flexible service, it is not yet clear whether the benefits outweigh the implementation challenges. However, there is likely value in ongoing IOU, Commission staff, and stakeholder work in this area.

Dynamic Operating Envelope Utilizing Grid Edge DERMS to Address Secondary Constraints

The same Dynamic Operating Envelope concept can also be applied to secondary distribution constraints, although the method of calculating available capacity differs. Secondary system Dynamic Operating Envelopes can be derived from Grid Edge DERMS technologies. As currently implemented in PG&E's EPIC 4.02A pilot, ChargeBoost, Grid Edge DERMS utilize contiguous customers' metering data via Radio Frequency mesh communications networks to create a virtual transformer model that estimates loading on shared service transformers and secondary conductors. Under this approach, devices located at customer sites exchange information regarding aggregate loading conditions and calculate

[49] PG&E November 25, 2025 response to ACR at 3-4; SDG&E November 25, 2025 response to ACR at 6-7.
[50] SCE EASE report at 47-48; PG&E November 25, 2025 response to ACR at 3-4.

Dynamic Operating Envelopes for customers that have limited site capacity, share constrained infrastructure, or both.

PG&E's ChargeBoost pilot provides an example of this architecture, demonstrating how distributed controls can increase utilization of existing secondary infrastructure while avoiding reliance on conservative planning assumptions. PG&E's ChargeBoost relies on AMI 2.0 meters, which communicate with neighboring meters, aggregating that information up to the transformer level. In this way, the meter is able to communicate to the transformer about grid conditions rather than the Enterprise DERMS approach that requires direct communication with the utility and its Enterprise DERMS. PG&E stated at the All-Party Meeting that it has made EPIC 4.02 Programs (i.e., ChargeBoost or PanelBoost) its default mitigation for secondary capacity constraints experienced by residential customers on 100 A services.[51]

In many cases, energy storage (e.g., EVs, Hot Water Heaters, etc.) is expected to be the primary enabling technology for flexible connections because it can absorb or supply power as operating limits change without requiring significant disruption to customer operations. As a result, Grid Edge DERMS-based Dynamic Operating Envelopes may provide a scalable pathway for increasing secondary-system hosting capacity while reducing the need for service transformers and secondary conductor upgrades. For this reason, the proposal recommends steps to advance Grid Edge DERMS-based Dynamic Operating Envelope offerings.

[51] All Party Workshop Recording, (https://youtu.be/68awo3HnNYU), PG&E Presentation starting at 1:15:36.

Section 5: Cybersecurity Considerations

The flexible connection frameworks discussed throughout this proposal rely upon communications pathways and control capabilities that extend beyond traditional distribution planning and operations. Variable Operating Envelopes, Enterprise DERMS based Dynamic Operating Envelopes, and customer-owned energy management systems all depend upon the secure exchange of information between utility systems and customers, including DER resources. As a result, cybersecurity considerations are a foundational requirement for implementation.

Fortunately, substantial work has already been completed through the Smart Inverter Operationalization Cybersecurity Subgroup (SIO-CS) established under Track 3 of this proceeding. The SIO-CS developed a phased set of DER cybersecurity requirements using IEEE 1547.3 as its foundation and recommended a regulatory pathway involving utility adoption of the Phase 1 requirements, continued development of Phase 2 requirements, and establishment of testing and certification programs for DER equipment and communications systems. The SIO-CS developed these recommendations to support the secure operationalization of smart inverters, DERMS, and related communications architectures necessary to enable firm and non-firm operating limits, Operating Envelopes, and other flexible connection solutions.

This proposal recommends that all flexible connection offerings utilizing communications capabilities consider the SIO-CS phased cybersecurity requirements as the baseline cybersecurity framework for all systems larger than 1 MW, per recommendations in the SIO-CS report.[52] This recommendation applies to non-firm limit frameworks and should encompass all energization pathways that rely upon customer-owned devices, communications gateways, or Enterprise DERMS platforms. To ensure consistency across utility territories while preserving flexibility for implementation, the large IOUs should be required to justify any deviations from the SIO-CS recommendations in their internal practices through a proposed implementation plan filed via AL. This proposed process is

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[52] Smart Inverter Operationalization Cybersecurity Subgroup Working Group Report (Attachment 2): https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M532/K683/532683550.PDF

described in more detail in Section 9. Utilizing the SIO-CS framework as a common foundation will help ensure that flexible connection solutions are implemented in a manner that is secure, interoperable, reliable, and aligned with California's evolving grid modernization objectives.

Section 6. Bridging and Non-Bridging Approaches

This section describes bridging and non-bridging solutions, separating non-bridging into persistent and durable options. Bridging and non-bridging solutions are triggered when the utility forecast of customer demand indicates that there is insufficient capacity for the IOU to perform that upgrade on the customer's requested timeline[53] or when a customer and the IOU come to mutual agreement that a solution involving a mitigation rather than an upgrade is acceptable. These solutions allow utilities and customers to utilize available capacity more efficiently by employing Limited Power, Operating Envelopes, or customer flexibility[54] rather than relying exclusively on the conventional solution of infrastructure replacement. The key distinction between bridging and non-bridging solutions is whether the flexible connection arrangement affects the timing or need for the planned upgrade. Bridging solutions provide temporary access to capacity while an upgrade proceeds upon its original schedule. Non-bridging solutions alter the timing, scope, or necessity of the upgrade and therefore create opportunities for ratepayer savings through deferral or avoidance of capital expenditures.

In order to safeguard ratepayer funds, new customers should not be able to switch back and forth between bridging and non-bridging solutions. There should be a fixed date, currently set at 45 days after the IOU presents the results of its engineering screens or analysis and proposed design, by which a customer must elect to pursue either a bridging or non-bridging solution.

Bridging Solutions

Bridging solutions do not alter the schedule or scope of planned upgrades, but allow the customer to increase their load within the limits of the existing infrastructure until such time as it can be upgraded. For example, in D.26-02-025 in the Energization Rulemaking the bridging solutions established did not defer or deprioritize any capacity infrastructure upgrades, and the Commission directed the IOUs that a customer's project could not be

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[53] PG&E December 16, 2024 Bridging Solutions Strategies Report at 1; SCE December 16, 2024 SCE's Bridging Solutions Strategies Compliance Report at 1; SDG&E December 16, 2024 Bridging Strategies Plan *passim*.

[54] Such as when a customer modifies operations to receive a conditional permission to operate.

moved up or down in the IOU's queue due to their participation in the flexible service connection.[55] In these cases, the ratepayer benefits from a bridging solution by the revenue associated with increased infrastructure utilization prior to the upgrade. The participating customer benefits from speed to power. They can largely achieve their operations within grid constraints until such a time as the upgrade can be completed. The utility may benefit from bridging solutions through improved customer relations.

Non-Bridging Solutions

For non-bridging solutions, there may be a ratepayer and a customer benefit to upgrade deferral even if they do not result in avoidance of the upgrade project. There are two types of non-bridging solutions: persistent and durable.

Persistent Non-Bridging Solution

A non-bridging solution that persists until a piece of equipment is replaced through normal utility operations unrelated to the solution (e.g., end of useful life, organic load growth from other customers, etc.) is called a persistent non-bridging solution. This is distinct from a bridging solution, like the ones established articulated in response to D.24-10-030,[56] as those bridging solutions still add the grid upgrade project to the IOU's queue whereas a persistent non-bridging solution does not. For the persistent non-bridging solution, the customer's project is not the driving factor for any future grid upgrade. An example of a current persistent non-bridging solution is the "as available capacity" feature of the IOUs' WDAT tariffs. WDAT customers are provided with a schedule of capacity values that exceed the single value from conventional forecasting and can use this capacity for their load without funding an upgrade as long as they comply with the given schedule.

A persistent non-bridging solution should be appropriate for Lateral primary customers where there is no established methodology to quantify additional revenue resulting from new and permanent load and/or existing customers transitioning from a

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[55] D.26-02-025 at page 37: "We clarify that customers utilizing a Standard Offer shall not have any change in their energization queue positions and that the IOU shall not change the prioritization of a capacity project based on customer participation in a Standard Offer. As the Standard Offer is a bridging solution that is offered only while the capacity is constrained, it should not impact the customer queue position or the capacity project prioritization."

[56] D.24-10-030 Ordering Paragraph 18, *passim*.

bridging to a non-bridging solution whose operating envelope and flexibility measures are already in place.

The ratepayer benefits from a persistent non-bridging solution by the revenue associated with increased infrastructure utilization prior to the upgrade. The ratepayer also benefits from not having to forfeit the undepreciated value of the existing distribution assets due to the asset being upgraded during its useful life. If multiple smaller upgrades can be combined into a single larger upgrade project, the ratepayer may benefit from economies of scale in the cost of that larger project. The participating customers benefit from speed to power, and from the ability to increase their operations without having to pay for an upgrade.

The utility may benefit from being able to combine capacity upgrades from multiple constraints into a single project. The utility may also benefit from reduced workload and cost, both for its internal labor and for the contracting involved with procuring contractor labor.

Durable Non-Bridging Solution

A durable non-bridging solution is one where the IOU and customer agree contractually to an arrangement in which a customer operates their equipment in a manner that resolves the capacity constraint using a control device. The customer is then able to receive service quickly, in a manner that is beneficial to the ratepayer, customer, and utility. Under the durable non-bridging solution, the customer would agree to maintain the flexible connection for a specified period and refrain from requesting an upgrade associated with that incremental capacity.

For ratepayers, durable non-bridging solutions offer the greatest potential benefits because they can avoid capital expenditures entirely, increase utilization of existing assets, preserve the remaining undepreciated value of constrained equipment, and generate additional utility revenue from increased energy consumption. Participating customers benefit from expedited access to capacity, avoided upgrade costs, reduced site disruption, and potential operational benefits associated with the enabling technologies. Utilities benefit from reduced construction workload, increased planning flexibility, and greater certainty regarding future infrastructure requirements. Examples of technology that could enable a durable non-bridging solution may include customer-sited batteries, managed EV charging systems, thermal storage, or other technologies capable of limiting site demand during constrained periods.

PG&E asserts[57] that this approach allows for the avoidance of the upgrade. Other parties have raised concern that the compensation amounts or the fees manufacturers or service providers charge to provide access to the customer owned equipment may counterbalance ratepayer savings from avoided upgrades or promote vendor lock-in.[58] While one approach to addressing these high customer costs would be an incentive or rebate structure based on the avoided upgrade cost[59] or customer allowance value[60] associated with the incremental load, this proposal does not explicitly recommend this.

Utilities benefit from reduced construction workload, increased planning flexibility, and greater certainty regarding future infrastructure requirements. Durable non-bridging solutions provide an opportunity for the Commission to explore a framework in which customers may voluntarily elect a flexible connection that provides substantial economic value without requiring that the utility continuously provides the capacity equal to the demand load under all operating conditions.

Electing Between Bridging or Non-Bridging Solutions

Flexible connection solutions exist along a continuum ranging from Bridging solutions to durable non-bridging solutions capable of avoiding infrastructure upgrades altogether. As customers gain experience with these offerings and as control technologies continue to mature, it is reasonable to expect that some customers will initially pursue conventional upgrades or bridging solutions and later elect to transition to a non-bridging solution. During the Track 3 workshop process, SCE raised concerns regarding the potential

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[57] Financial justification for the EPIC 4.02A project assumes cost savings due to avoiding the need to upgrade a service transformer.

[58] Workshop recording (https://youtu.be/68awo3HnNYU) at ~1:52:30, 6:14:00; SDG&E's December 19, 2025 response to ACR at 5, 9-10; Universal Devices' April 4, 2026 Comments on All-Party Workshop Report at 6.

[59] PG&E January 16, 2024 EPIC Workshop Slide 27 – typical residential panel upgrades (customer cost) can cost $3-5k and typical residential service upgrades (ratepayer cost) can be $5-8k with some scenarios costing above $20k.

[60] Non-Residential Customers' allowance is determined using the formula in Electric Rule 15 Section C.2. using their forecast or actual annual revenue, and reviewed pursuant to Electric Rule 15 section E.3.b.

for such transitions to create stranded utility costs if planning, engineering, procurement, or construction activities have already commenced.[61] This proposal recognizes those concerns and recommends establishing a policy that both preserves the affordability benefits of flexible connection solutions and ensures that utilities can recover prudently incurred costs associated with customer-driven project changes.

Under such a policy, the Commission should seek to ensure that savings associated with non-bridging solutions are not overwhelmed by costs associated with utility dependencies, site readiness, construction, or other costs associated with further energization steps due to a customer requesting transition to a bridging solution.

However, allowing for some flexibility for existing flexible service connection customers[62] to make this request may still provide ratepayer benefits from avoiding a future upgrade even when certain development costs have already been incurred. This proposal finds that balance can be struck by ensuring that these existing customers can make a request to transition to a non-bridging solution up until the later of 45 days after receiving the IOU design or 45 days after the issuance of a Track 3 decision. At that time, the customer should either approve that design to move forward with the bridging solution or elect a non-bridging solution. For those projects that transition to non-bridging, utilities should retain the ability to recover prudently incurred costs associated with work already performed on behalf of that project.

This proposal explores whether certain flexible service arrangements can persist beyond the period traditionally associated with energization delays and serve as non-bridging solutions that defer or avoid upgrade costs. In doing so, the Commission can evaluate whether customer-elected flexible service should serve not only as a temporary bridge to traditional upgrades, but also as a long-term mechanism for increasing utilization of existing distribution infrastructure, reducing ratepayer and customer costs, and supporting electrification.

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[61] Southern California Edison Comments on Track 3 Workshop Report at 4. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M604/K025/604025670.PDF

[62] Existing customers include those currently taking service on PG&E's Load Limit Letter, Flex Connect, or Standard Offer as well as those on SCE's LCMS or Standard Offer

Section 7. Competition and Market Access Considerations

The flexible connection frameworks discussed throughout this proposal rely on increased visibility into distribution system constraints and, in some cases, the ability to coordinate customer-owned equipment in response to those constraints. During the Track 3 workshop process, parties raised concerns regarding how access to both customer equipment and distribution system information may affect competition and customer choice. IOUs noted that some vehicle Original Equipment Manufacturers (OEMs) maintain proprietary communication pathways to customer-owned devices and may charge fees for third-party access to those devices. At the same time, CalCCAs, aggregators, and technology providers expressed concern that the operational information generated by utility Enterprise DERMS platforms could become available to utility programs while remaining inaccessible to other market participants capable of providing equivalent services.[63] Taken together, these concerns highlight the importance of ensuring that flexible connection frameworks do not inadvertently create barriers to participation or confer undue advantages on particular technologies, vendors, or market actors.

Information regarding capacity constraints, available flexible capacity, and Operating Envelope requirements should be made available, consistent with existing customer privacy, cybersecurity, and grid reliability requirements. Customers should retain the ability to choose how they satisfy flexible connection requirements, whether through utility programs, OEM-provided solutions, third-party aggregators, CCAs, or self-managed equipment. This could promote innovation, reduce costs, and help ensure that the economic benefits associated with flexible connections accrue to customers and ratepayers rather than being concentrated among a limited number of technology providers.

At a minimum, customers should retain the ability to authorize participation in utility, CCA, aggregator, or other approved programs without being restricted by proprietary arrangements. Establishing basic interoperability and control requirements will help ensure that ratepayer-funded investments remain useful throughout the life of the equipment,

[63] Track 3 All Party Workshop Report at 136-140: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M602/K998/602998929.PDF

reduce the risk of vendor lock-in, and support a competitive marketplace capable of delivering flexible capacity solutions at the lowest reasonable cost.

This proposal recommends that a workshop process explore these issues in more depth.

Section 8. Real-Time Pricing and Economic Signals for Flexible Connection Customers

Several parties have suggested that Variable Operating Envelope and Dynamic Operating Envelope customers may be particularly well suited to participate in Real-Time Pricing (RTP) programs.[64] Customers electing flexible service arrangements have already demonstrated a willingness to respond to changing grid conditions and may be the customers most likely to benefit from dynamic price signals. The Commission's recently opened Advanced Rate Design proceeding (R.26-04-009) is examining key issues related to RTP, including key customer protections and education requirements.

There are important economic reasons to consider the alignment between flexible connection frameworks and the Commission’s ongoing work on RTP. Variable and Dynamic Operating Envelopes communicate information regarding the physical availability of distribution capacity, while RTP communicates information regarding the economic value of electricity at a given time. In many circumstances, these signals can be complementary. Periods of abundant distribution capacity are often associated with lower system costs, while periods of distribution constraints frequently coincide with higher system costs. Aligning operational flexibility with price signals can encourage customers to shift consumption toward periods when both distribution load capacity and energy supply are plentiful, improving overall utilization of the electric system and reducing costs for all customers.

Customers operating under Variable or Dynamic Operating Envelopes may deploy flexible load controls or storage to manage changes in available capacity. These same technologies can respond to dynamic price signals by charging during lower-cost periods and reducing consumption or discharging during higher-cost periods. Customers enrolled in RTP have a significant number of hours where their price for energy is lower than the comparable time of use rate.[65] As a result, storage-equipped flexible connection customers or those with

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[64] SDG&E November 25, 2025 response to ACR at 3; The Mobility House December 18, 2025 Opening Comments on ACR at 3; SCE Opening Comment on ACR at 12.

[65] Energy Division analysis of A.24-06-014 workpapers.

EV charging capable of charging and discharging may be able to capture additional economic value while simultaneously supporting grid operations.

More broadly, widespread adoption of flexible connection solutions coupled with efficient price signals has the potential to increase utilization of existing infrastructure, reduce the need for costly distribution upgrades, and place downward pressure on customer rates by making better use of both distribution and generation resources. As such, this proposal recommends that IOUs default enroll flexible connection customers onto appropriate RTP rates, while allowing customers to opt out.

Section 9. Recommendations for Commission Action

This section includes recommendations and proposed Commission actions to build upon the foundation established in this proposal and the discussions in Track 3 of the High DER proceeding. The recommendations focus on advancing IOU flexible solutions offerings as a mitigation before proceeding with upgrades, where warranted, developing long-term flexible service offerings for load customers that include creating durable non-bridging pathways, and moving towards incorporation of these offerings within the utility Distribution Planning Process. As outlined throughout this proposal, the objective of these proposed actions is to support ratepayer affordability while maintaining grid reliability and timely customer service.

The Commission should direct the large IOUs to develop standardized flexible connection solutions built around non-firm capacity offers for load customers experiencing capacity constraints. Building upon the Standard Offer framework established in the Energization proceeding and current large IOU practices, these offerings would provide customers with a transparent choice between traditional infrastructure upgrades and the flexible service alternative(s) appropriate to their distribution infrastructure.

While there is certainly value in also addressing flexible generation solutions that are similar, this proposal focuses primarily on service, deferring the generation work for consideration in the Interconnection Rulemaking (R.25-08-004). However, learnings from the implementation of flexible service solutions that result from this proposal and any subsequent Commission Decision should inform policy, to the extent reasonable, on interconnection.

The following recommendations are organized by the relevant sections within this proposal. As Section 1 (Introduction) and Section 2 (The Affordability Opportunity: Reducing Customer and Ratepayer Costs Through Flexible Capacity Solutions) both focus on background alone, the proposal's recommendations begin with Section 3.

Section 3 Recommendations: Distribution Capacity Determination, Existing Infrastructure, Forecasting Practices, and Capacity Evaluation Methods

This proposal recommends that the Commission direct the large IOUs to establish standard flexible service connection offers that are appropriate to customer size and infrastructure, include clear descriptions of expected operation based upon available capacity, customer equipment obligations, and applicable rate structures.

Recommendations for Commission action related to this section are articulated below:

1. **Extension of Standard Offer to SDG&E customers:**

D.26-02-025 in the Energization Rulemaking directed SCE and PG&E to establish a Standard Offer for flexible service connections based on record of untimely energization. As the Energization Rulemaking is focused on energization timelines and there was no record of SDG&E experiencing untimely energization, the Commission did not direct SDG&E to establish a Standard Offer in that venue. However, the High DER proceeding and this ACO proposal are focused on ratepayer savings and maximizing the effective usage of grid infrastructure by leveraging the benefits available through flexible service connections.

Thus, to capture these benefits, this proposal recommends the Commission direct SDG&E to implement a Static Operating Envelope Standard Offer. This implementation should follow the same actions articulated in D.26-02-025 Ordering Paragraphs 1 through 5. This proposal recommends that SDG&E should file a Tier 2 AL within 120 days of issuance of the Track 3 decision to describe its implementation plan and timeline (Tier 2 FSC Implementation AL).

2. **Large IOUs to record and provide values helpful to dedicated infrastructure customers independently implementing Operating Limits:**

D.26-02-025 in the Energization Rulemaking took action allowing customers served by dedicated infrastructure to add load controlled to an operating limit independent of large IOU involvement. This recommendation aims to build off that work to improve alignment between load the customer is controlling and the utility process for determining the site load.

This proposal recommends the Commission direct the large IOUs to record the service conductor capacity and demand load values for each site as they are computed in the Engineering and Design energization step.

As this process does not currently exist in the IOUs' tariffs or Electric Rules, the implementation of this recommendation should be formalized via Tier 2 AL (Tier 2 FSC Implementation AL). The customer process for requesting and receiving this information should be consistent across the large IOUs to ensure ease for customers. These values, or confirmation that the IOU does not have recorded values for that site, shall be given within 30 days of customer request.

3. Rule 2—Updating definition of Controlled Load and alignment language between Large IOUs:

In order to effectively implement Limited Power arrangements, Rule 2 would benefit from modifications that better align customer actions with utility expectations. As noted above, D.26-02-025 implemented changes to Rule 2 and this proposal recommends that the additional metrics of demand load and secondary conductor rating be added, when available, to improve the alignment between Large IOU demand assumptions and the customer's Limited Power setpoint.

This proposal recommends the Commission direct the large IOUs to modify their Rule 2 Section H.7 to reflect that the PCS limit for controlled load shall be the lesser of connected load, demand load, or secondary conductor rating.[66]

Further, this proposal recommends the Commission direct SCE and SDG&E to align their Electric Rule 2 language with PG&E's section F.2 language, citing IEEE 519 as the standard by which Harmful Wave Form and Harmonics shall be judged.

While aligning their Electric Rule 2 with PG&E's, the Commission should also direct SCE and SDG&E to review their Rule 2 document to identify incidences of gendered language (e.g., his premises) and replace those incidences with non-gendered (e.g., their

[66] Current Rule 2 Section H.7 language states "…PCS limits power into the facility such that it will not exceed the connected load of the remaining electric utilization equipment, that is known as controlled load." Adding "the lesser of the secondary conductor rating, demand load, or" between the words "the" and "connected" would accomplish this purpose.

premises) language, as found in PG&E's Rule 2. Large IOUs may, if desired, review the remainder of their Electric Rules and in consultation with Energy Division, use this AL as a vehicle to excise incidences of gendered language from additional Electric Rules. This proposal recommends that the IOUs include this in the Tier 2 FSC Implementation AL.

4. **Flexible connection evaluation requirements:**

This proposal recommends that before initiating a ratepayer-funded distribution upgrade, each IOU must evaluate whether a Limited Power arrangement, Operating Envelope, or other flexible connection solution enabled by PCS can be used as a mitigation to safely satisfy the customer's requested capacity. The mitigation option resulting from this evaluation should be documented and communicated to the customer prior to an IOU moving forward with engineering and design of the upgrade.

This proposal recommends that the Commission adopt this as an IOU requirement and direct the IOUs, in the Tier 2 FSC Implementation AL, to describe how they will implement this requirement, including descriptions of a) proposed criteria to identify eligible customers for the appropriate flexible connection that is consistent across the large IOUs, b) the evaluation process, c) the documentation process, and d) the customer communication process for presenting flexible connection mitigation options. This proposal recommends that after initial approval of the Tier 2 FSC Implementation AL, any updates to this process be included in the annual distribution planning proposals.

Section 4 Recommendations, Operating Envelopes and Dynamic Capacity Management

Based on the flexible connection tiers discussed above in Section 4, this proposal aims to further expand existing options, while setting in motion steps to allow for the implementation of novel approaches to Operating Envelopes.

Regarding Limited Power, Static Operating Envelopes, Variable Operating Envelopes, and DERMS-based Dynamic Operating Envelopes, this proposal makes the following recommendations for Commission action:

1. **Large IOUs to provide Limited Power arrangements as the default mitigation for distribution transformer upgrades:**

To enable flexible service offerings for Lateral primary customers, the Commission should direct the large IOUs to incorporate Limited Power implemented by certified UL 3141 devices as the default mitigation for distribution transformer or secondary conductor upgrades. This mitigation option should be offered to the customer after the engineering or initial study process establishes the available capacity and before the upgrade design process is initiated.

As existing IOU practices and Electric Rules already allow a utility to make mitigations to provide service, the large IOUs can implement this change without additional Electric Rule modifications. This proposal recommends that the Commission direct the large IOUs to implement this change and detail the workflow and customer communications involved through the Tier 2 FSC Implementation AL.

2. **SCE and SDG&E to implement Variable Operating Envelope bridging solutions modeled after PG&E's Flex Connect:**

PG&E has shown, through its Flex Connect offering, that it is possible to implement a IEEE 2030.5 based solution, at a low-cost,[67] that provides bridging capacity to load customers and non-bridging capacity to generation customers at a higher service level than the existing Limited Generation Profiles offering. While the communications infrastructure is likely too costly and the required power flow model is likely unavailable for smaller customers,[68] the Flex Connect model PG&E has established serves as a working structure and communications architecture[69] to provide this offering for larger customers served by Mainline. As SCE has experience with its LCMS pilot and SDG&E has experience with its WDAT pilot, it is realistic to expect that SCE and SDG&E can implement a similar offering to Flex Connect within one year of the adoption of a Track 3 decision.

This proposal recommends that the Commission direct SCE and SDG&E within a Tier 3 AL, the Flex Connect AL to describe their implementation plan for this offering

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[67] Smart Inverter Working Group PG&E OpFlex Pilot Report, February 2025 at 4: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/rule21/smart-inverter-working-group/pge_opflex_report_2025.pdf

[68] Ibid; All Party Workshop Report at 54-60

[69] PG&E November 25, 2025 response to ACR at 8; SCE December 19, 2025 response to ACR at 6; Clean Coalition December 19, 2025 Comments on ACR at 4; IREC December 19, 2025 Comments on ACR at 9-11.

within the one-year timeframe. However, SCE and SDG&E should also be required to give quarterly updates to Energy Division staff on their progress and provide a preview workshop six months after issuance of a Track 3 Decision to get stakeholder feedback on their draft implementation plans. The Flex Connect AL should reflect feedback from Energy Division staff and stakeholders.

3. Leveraging Enterprise DERMS based Variable Operating Envelope infrastructure for centralized Dynamic Operating Envelopes to address abnormal grid conditions:

The November 2025 ACR posed questions to parties regarding the use case for Dynamic Operating Envelopes in the case of suddenly emergent grid conditions, in order to allow near real-time communications for customers to reply to signaled maximum import values. Several parties expressed interest in developing this Dynamic Operating Envelope use case, while other parties indicated concern that the benefits may not justify the cost of the development effort.[70]

There may be value in developing these options further to create flexibility for customers situated at sensitive portions of the grid and for enabling the IOUs to address emergent situations. However, given the lack of interest from other parties and need for additional research on whether existing Variable Operating Envelope infrastructure can be repurposed to provide Dynamic Operating Envelopes, this proposal recommends that the large IOUs host a workshop to further the discussion on Dynamic Operating Envelopes and submit a workshop report within one-year of a decision on Track 3.

4. SCE and SDG&E should implement Grid Edge DERMS for 100 A residential customers whose EV charging would normally require an upgrade:

As discussed in Section 4, there is significant opportunity for Dynamic Operating Envelopes using Grid Edge DERMS. The key challenge for implementing Dynamic Operating Envelopes is the ability to rapidly measure and apportion capacity. This challenge makes provisioning a Dynamic Operating Envelope from Enterprise DERMS, in which

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[70] Cal Advocates December 19, 2025 Comments on ACR at 1,2; UCAN December 19, 2025 Comments to ACR at 3.

signals must be sent to and from the utility, infeasible for large numbers of customers. However, using Grid Edge DERMS, PG&E's ChargeBoost pilot has developed a novel way to address this challenge for 1,000 residential EV customers on 100A services, as discussed in Section 4. Given the outsized role that EV charging and secondary upgrades play in projected infrastructure costs, SCE and SDG&E should implement the approach of using a Grid Edge DERMS that monitors transformer loading and uses local controls to modulate EV charging.

This proposal recommends that the large IOUs file a Tier 2 AL (Tier 2 Grid Edge DERMS AL) addressing initial Grid Edge DERMS offerings. SCE and SDG&E should describe in the Tier 2 Grid Edge DERMS AL how they plan to implement a ChargeBoost-like program of their own, establishing the offering within six months of a decision on Track 3. The Grid Edge DERMS AL should additionally describe any differences in implementation plan with PG&E's ChargeBoost, along with an explanation.

All three large IOUs should propose in their Tier 2 Grid Edge DERMS AL how they plan to scale this offering beyond the first 1,000 customers and whether this approach should become the default mitigation for all residential EV customers, not just those on 100 A services.

5. **Establish a series of Energy Division-led workshops with reports to further develop Grid Edge DERMS solutions:**

While each of the large IOUs will soon have a Grid Edge DERMS solution offering modeled on ChargeBoost, many Grid Edge DERMS design questions remain unaddressed. These include:

- The issues of capacity sharing,
- Application authoring and program access, including for CCAs,
- Whether AMI meters are the appropriate long-term solution for computing the Operating Envelope, and
- Ensuring that more devices than EV chargers can be locally controlled to ensure rapid response and prevent ongoing access fees.
- Identifying any generation-related interactions or issues that should be considered.

This proposal recommends that a series of Energy Division-led workshops be established to address these matters. Stakeholders should include interested parties to this proceeding, California Energy Commission staff, and interested stakeholders from the Vehicle-Grid Integration Forums. Following the workshops, one or more staff workshop reports should be circulated to the service lists for this proceeding, the Transportation Electrification Policy and Infrastructure (TEPI) proceeding (R.23-12-008) Interconnection proceeding, and Energization proceeding and submitted to the record of any successor proceeding to the High DER proceeding.

Section 5 Recommendations, Cybersecurity Considerations

Track 3 of the High DER proceeding examined cybersecurity considerations through the SIO-CS working group and report. This proposal provides a foundation for future action on cybersecurity considerations, as articulated in the following recommendation:

1. **Direct IOUs to propose implementation of baseline cybersecurity considerations from the SIO-CS:**

Establishing baseline cybersecurity considerations from the SIO-CS: This proposal recommends that all non-firm limit flexible connection offerings for interconnection and energization utilizing communications capabilities consider the SIO-CS phased cybersecurity requirements as the baseline cybersecurity framework for all systems larger than 1 MW. This recommendation applies to pathways that rely upon customer-owned devices, communications gateways, aggregators, DERMS platforms, or other control systems.

This proposal recommends that IOUs host workshops to vet how best to implement the SIO-CS phase 1 recommendations. Following the workshop, the IOUs should prepare a summary workshop report that includes an initial implementation proposal for the baseline cybersecurity framework. This should include justification for any deviations from the SIO-CS recommendations in their internal practices. Any justification for a deviation should address how the deviation will support improved security, interoperability, reliability, how it aligns with California's evolving grid modernization objectives, and how it avoids being overly restrictive to customers and third parties. This should be served to the service lists of the following proceedings and IOUs should allow for informal comments to be submitted from parties and staff: High DER, TEPI, Interconnection, Advanced Rate Design, and Demand Response (R.25-09-004). Following the informal comment period, the IOUs should submit the workshop report, summary of informal comments, and implementation proposal, adjusted based on comments, through a Tier 2 AL (Tier 2 Cybersecurity Implementation AL).

The following is this proposal's recommendation for timing of these actions:

- IOUs host initial workshop –90 days following a Commission Decision on Track 3.
- IOUs serve workshop report and initial implementation plan to service list - 60 days following initial workshop.
- IOUs hold second workshop to discuss proposal and respond to any questions – 20 days after issuance of workshop report.
- Informal comments submitted – 35 days after initial workshop.
- IOUs file Tier 3 Cybersecurity Implementation AL – 60 days after comments filed.

Section 6 Recommendations, Bridging and Non-Bridging Approaches

While bridging solutions have been a Decision and report topic, non-bridging approaches offer a new area of possibility for the IOUs. The following summarizes this proposal's recommendations related to bridging and non-bridging approaches:

1. Establish durable non-bridging solutions for new flexible connections:

As discussed in this proposal, durable non-bridging solutions can provide ratepayer, customer, and utility benefits. As SDG&E does not have any current bridging offerings to base a non-bridging option upon, this recommendation focuses on PG&E and SCE. The Commission should direct PG&E and SCE to each establish a process for providing durable non-bridging versions of currently available standard flexible service connection offerings.[71] The IOU proposals for this process should include a mechanism to monitor and report

[71] Customer-owned generation, storage, managed charging, or other controlled technologies are some examples of how customers will be able to ensure these solutions are durable.

upon how long-term flexible service arrangements can safely defer or avoid distribution infrastructure upgrades while providing net benefits to ratepayers and participating customers.

This proposal recommends that the Commission direct PG&E and SCE to file a joint Tier 2 AL (Tier 2 Non-Bridging Solutions AL) with their proposal for offering durable non-bridging versions of each of their flexible service connection offerings, which should be filed within 90 days of the adoption of a Decision on Track 3. The Tier 2 Non-Bridging Solutions AL should address the following:

- How each IOU plans to begin this offering with a limited number of customers within one year.
- Proposed definition for length of time "durable" covers, which should be consistent across the three IOUs.
- Proposed plan for data tracking and evaluation to measure customer interest, participation, and impact on customer and ratepayer costs.
- How each IOU would plan to scale this offering to a larger number of customers following the initial evaluation.

2. **Clarification that current Static and Variable Operating Envelope customers can elect to transition from a bridging to a persistent non-bridging solution:**

This proposal recommends clarification that current Load Limit Letter, LCMS, Standard Offer, and Flex Connect customers who have found that a bridging solution meets their operational needs can elect to take service under their current terms without triggering an upgrade. Thus, this would enable a customer to move from a bridging to a non-bridging solution.

However, in order to ensure the utility and ratepayers are not responsible for the costs of unnecessary infrastructure that may have been already built to serve the then-bridging customer's request, customers should only be eligible to make this request up until 45 days after presentation of design.

Even with this cut-off, large customers utilizing one of these offers may still incur some expenses. As they were incurred in good faith by both customer and utility, IOU engineering and design costs incurred prior to the customer opt out should be rate based. Current customers who have opted out of an upgrade in favor of a persistent non-bridging solution should be prevented from then requesting an upgrade for that load for a reasonable period of time.

This proposal recommends that the Commission direct the IOUs to include a plan within a Tier 2 AL (Tier 2 FSC Implementation AL) to implement this transition from bridging to non-bridging.

3. PG&E should formalize its Flex Connect offering and expand its non-bridging Flex Connect Generation option to load customers:

The Flex Connect program described in Section 4 has moved out of pilot status and is now a regularly utilized connection and operational tool. Making Flex Connect a tariffed offering would enable customer awareness and address Public Utilities Code Section 489(a). PG&E utilizes its Flex Connect offering described in Section 4 to provide non-bridging Variable Operating Envelopes to its Flex Connect generation customers. The simple change to expand this practice to load customers would unlock the non-bridging benefits discussed in Section 6. During the All-Party Meeting, PG&E expressed interest[72] in a program allowing for flexible connection to Rule 29 customers; this non-bridging Flex Connect for load offering may be an appropriate venue for Rule 29 customers whose load is largely served by existing infrastructure.

This proposal recommends the Commission direct PG&E to file a Tier 2 AL, the Non-Bridging Solutions AL, that establishes the Flex Connect processes and criteria and details the customer outreach process.

4. Large IOUs should be required to implement a non-bridging version of the Standard Offer:

This proposal recommends that the Commission direct the Large IOUs to establish a scaled process for providing non-bridging versions of the Standard Offer. This non-bridging process will utilize Standard Offer infrastructure scheduled to be in place to unlock the ratepayer benefits articulated in Section 2 of this proposal.

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[72] All Party Workshop Recording, (https://youtu.be/68awo3HnNYU), PG&E Presentation starting at 1:15:36.

This non-bridging Standard Offer should differ from the bridging Standard Offer in its equipment requirements and duration. Given that the bridging Standard Offer is only expected to be in place for 3 years,[73] non-certified controls are an acceptable option. For the non-bridging Standard Offer, however, UL 3141 certified controls should be a requirement. We recommend setting the duration of a non-bridging Standard Offer to 10 years; this term is likely to be aligned with the duration of warranty for control equipment and strikes a balance between assuring benefits and allowing customer flexibility if their long-term circumstances should change.

In a Tier 2 AL (Tier 2 Non-Bridging Solutions AL), the IOUs should articulate their implementation of this non-bridging Standard Offer, including the following:

- Whether the IOU proposes a cap on participation, and if so, what the initial cap would be and whether that will be established by number of customers or amount of load.
- Proposed plan for data tracking and evaluation in order to measure customer interest, participation, and impact on customer and ratepayer costs.
- How each IOU would plan to scale this offering to a larger number of customers following evaluation.

Section 7 Recommendations: Competition and Market Access Considerations

Establishing expectations around interoperability is critical to support market access and fair market competition. As such, the following recommendation addresses competition and market access considerations:

1. Interoperability and Customer Choice Requirements:

Any customer participating in a flexible connection offering should retain the ability to participate in utility, CCA, aggregator, or self-managed programs without being restricted by proprietary vendor arrangements.

[73] D.26-02-025 at 10.

This proposal recommends Energy Division staff host a workshop that includes technology providers, utilities, CEC staff, and CCA representatives to discuss reasonable guardrails to ensure interoperability, customer choice, and local control where feasible. IOUs should file a workshop report and serve it to this service list and the Data Access and Cost Effectiveness Rulemaking (R.22-11-013) service list, and file it within any successor proceeding to High DER.

Section 8 Recommendations: Real-Time Pricing and Economic Signals for Flexible Connection Customers

The purpose of addressing Real-Time Pricing (RTP) in this proposal is to ensure that flexible connection customers are not only aware of and abiding by the established limitations on their consumption related to the distribution infrastructure, but also to maximize utilization of grid assets by being responsive to pricing signals. The following recommendations address this alignment:

1. Real-Time Pricing Rate Enrollment

This proposal recommends the Commission direct the large IOUs to default any customer taking service[74] on a Variable or Dynamic Operating Envelope to an RTP rate. The customer can opt out of the RTP rate enrollment at the time of taking service under a Variable or Dynamic Operating Envelope and shall retain the ability to return to their prior rate.

2. Data Tracking

This proposal additionally recommends the Commission direct the IOUs to track data related to flexible connection customer enrollment in RTP rates, as well as opt-out levels. The IOUs should include within the Tier 2 FSC Implementation AL a proposal for data tracking, which at minimum should include:

- Customer type and representative load curve,
- Size of customer service (A),
- Location of customer,

[74] Taking service includes both energizing new load and receiving permission to operate generation equipment.

- Flexible connection offering/program,
- Bridging vs. non-bridging customer,
- Whether enrolled on an RTP rate:
- If yes, which rate,
- If not enrolled in an RTP rate, reason given for opting out.

The IOUs should include its proposed data tracking within its Tier 2 FSC Implementation AL.

These recommendations aim to expand and formalize the IOUs' flexible connections offerings and establish practical implementation pathways. It is the objective of these recommendations and proposal to use flexible connections as a tool to better utilize existing distribution infrastructure, reduce ratepayer costs, and maintain grid reliability. If done effectively, this approach can support electrification, improve grid utilization, and help ensure that California's clean energy transition is achieved in a manner that is both reliable and affordable for all customers.

Appendix A: Glossary of Terms

Advanced Distribution Management System (ADMS) A software platform that supports the full suite of distribution management and optimization. An ADMS includes functions that automate outage restoration and optimize the performance of the distribution grid. ADMS functions being developed for electric utilities include fault location, isolation and restoration; volt/volt-ampere reactive optimization; conservation through voltage reduction; peak demand management; and support for microgrids and electric vehicles.[36]

Bridging refers to temporary solution(s) put in place to allow a customer to operate on a limited basis until grid upgrades can be completed.

Customer is defined as the entity that receives or is entitled to receive Distribution Service through Distribution Provider's Distribution System or is a retail Customer of Distribution Provider connected to the Transmission System.[37]

Distributed Energy Resources (DER) means "distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies" (AB 327 and Section 769(a)).

Distributed Energy Resources Implementors (DER Implementors): Entities responsible for deploying, configuring, and maintaining DER systems in the field, ensuring their operational readiness and ongoing compliance with interconnection requirements.

Distributed Energy Resources Management System (DERMS) A platform which helps distribution system operators manage grids that include significant numbers of DERs.[40]

Electrically Contiguous refers to a set of sites that have electric service derived from the same utility distribution transformer's secondary.

Energization and **Energize** mean connecting customers to the electrical grid and establishing adequate electrical capacity.

Flexible Connection is defined as a means of connecting a customer to a utility's distribution system under specific capacity limits that may vary over time.

Flexible Service Connection is a flexible connection provided for the purpose of serving customer load.

Flexible Generation Connection is a Flexible connection provided for the purpose of serving customer generation.

Firm Capacity is load or generation capacity that is contractually obligated and remains in place.

Grid Upgrades are infrastructure additions or modifications undertaken to provide capacity that result in a capital project and take significant time to implement.

Limited Load Profile (LLP) means a static profile, or schedule, to be attached to flexible service connection agreements governing load power imports.
It contains information on the maximum power that can be imported from the grid by the customer at any given time.

Limited Generation Profile (LGP) means a static profile or schedule, to be attached to Flexible Interconnection Agreements governing generation power exports.
It contains information on the maximum power that can be exported to the grid by the customer at any given time

Mitigations are no- or low- cost near-term measures taken to resolve a capacity constraint.

Default Mitigation is the initial course of action evaluated when a grid connection issue is identified (e.g., capacitors for power factor issues, switching phases for imbalance issues, the list in Rule 21 section G.1). This evaluation occurs prior to the consideration of an upgrade.

Near Real-Time Communications are communications with latency of a few minutes between the occurrence of an event and the receipt of information on that event.

Operating Envelope is the series of operational limits, based on firm and non-firm capacities, within which customers may import and/or export power over a specified time frame (e.g., one day). Operating Envelopes always apply to a customer's power exchange with the operator at the point of common coupling (PCC).

Dynamic Operating Envelope is a Variable Operating Envelope whose operational limits may be updated in near real-time to reflect an updated understanding of additional non-firm capacity.

Static Operating Envelope is an Operating Envelope whose collection of operational limits is predetermined to reflect known firm capacity and may not be modified without altering the contract between customer and operator. This envelope is described by a limited load profile (LLP), a limited generation profile (LGP), or both.

Temporary Operating Envelope is an Operating Envelope that remains in effect for a specific amount of time (e.g., bridging solutions).

Variable Operating Envelope is an Operating Envelope whose collection of operational limits is persistent, based on known firm and non-firm capacity over a predetermined period and modified periodically (e.g., day-ahead). The new collection of limits supersedes the old collection and becomes effective at an agreed upon time.

Operational Flexibility refers to the ability of the grid operators to optimize the use of existing capacity based on forecasted or near real-time grid conditions, accelerating safe and reliable connection of DER and loads.

Point of Common Coupling. The point at which the electrical conductors of Distribution Provider intersect the electrical conductors of the customer.

Power Control System (PCS) is a system that monitors the output of power sources and/or power consumption of loads and regulates or limits power exchange between the customer and operator within predefined limits.

Speed to Power: The use of a flexible connection to unlock faster grid access in a way that puts downward pressure on rates.[75]

Uniform Integration Capacity Analysis (ICA) is a tool used to calculate modeling results that represent the maximum uniform power available to serve load (Load ICA) or export capacity available (Generation ICA) at the point of common coupling without violating the thermal, voltage variation, and steady state voltage criteria. The results from this

[75] Adapted from the May 21, 2026 High DER Track 2 DER Orchestration Workshop Presentation

tool take the form of a set of power values that represent capacity available during different periods of time.