

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**



FILED

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

Rulemaking 21-06-017
(Filed June 24, 2021)

11/25/25
04:59 PM
R2106017

**OPENING COMMENTS OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E)
IN RESPONSE TO ASSIGNED COMMISSIONER'S RULING SEEKING
ADDITIONAL INFORMATION ON DER ENABLED NEAR TERM FLEXIBLE
CONNECTIONS**

Roger A. Cerda
8330 Century Park Court, CP32D
San Diego, California 92123
Telephone: (858) 654-1781
Email: rcerda@sdge.com

Attorney for:
SAN DIEGO GAS & ELECTRIC COMPANY

November 25, 2025

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

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

Rulemaking 21-06-017
(Filed June 24, 2021)

**OPENING COMMENTS OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E)
IN RESPONSE TO ASSIGNED COMMISSIONER’S RULING SEEKING
ADDITIONAL INFORMATION ON DER ENABLED NEAR TERM FLEXIBLE
CONNECTIONS**

I. INTRODUCTION

Pursuant to the California Public Utilities Commission’s (“CPUC” or “Commission”) November 3, 2025 *Assigned Commissioner’s Ruling Seeking Additional Information on DER Enabled Near Term Flexible Connections* (“Ruling”), San Diego Gas & Electric Company (“SDG&E”) hereby submits its Opening Comments. An Administrative Law Judge email ruling, dated November 14, 2025, modified the date for the Large Investor-Owned Utilities (“Large IOUs”) responses to questions 19, 21, and 22 of the Ruling from December 10, 2025, to November 25, 2025. A further Administrative Law Judge email ruling, dated November 19, 2025, modified the response date for Parties’ opening comments on the November 3, 2025 Ruling from December 10, 2025, to December 19, 2025. It also modified the response date for Parties’ reply comments to the Ruling from December 22, 2025 to January 2, 2026.

In addition to requiring the Large IOUs to respond to specific questions, the Ruling directs the Large IOUs to:

- Confer with parties to identify dates of mutual availability for an all-party meeting¹ to be held between January 5-16, 2026.

¹ The Ruling specifies that “The all party meeting will be utilized as an interactive meeting where parties will have an opportunity to summarize their key recommendations from comments, respond to other parties, address questions from the assigned commissioner and assigned administrative law judges as well as engage in organized questions and dialogue between parties. This meeting will be organized differently than a traditional all party

- Ensure that personnel capable of responding to technical inquiry regarding the topics of Distributed Energy Resources Management System (“DERMS”), Advanced Distribution Management System (“ADMS”), Limited Load Profiles (“LLPs”), FlexConnect, Load Control Management Systems, and Institute of Electrical and Electronics Engineers standard 2030.5 (“IEEE 2030.5”) communications systems are made available for the all-party meeting.
- Submit a summary of party availability including identification of which persons are expected to represent each party along with their initial response to this ruling.²

The Ruling specifies that any materials relied upon for presentation shall be distributed to the service list no later than one week prior to the all-party meeting.³

Pursuant to the Ruling, and the November 14, 2025 email ruling, below are SDG&E’s responses to questions 1-15, 19, 21, and 22 of the Ruling. For ease of reference, SDG&E addresses each issue by reference to the numbering designations used in the ruling.

II. DISCUSSION

As an initial matter SDG&E observes that, while unstated, the Ruling’s questions presume that the programs, tariffs, contracts, Behind-The-Meter technologies and back-office systems necessary for customers to effectuate and adhere, on a day-ahead or near real-time basis, to utility-initiated import and export limits, will be put in place. Very little is in place now. Programs have not been defined. The incentives necessary for customers to adjust their imports or exports in response to utility dispatch signals have yet to be established. There is no robust analysis available now that indicates whether such incentive levels would be cost-effective, either to the

meeting and will function in a manner similar to a combined workshop, status conference, and traditional all party meeting.” Ruling, footnote 26.

² The summary of availability has been provided to the service list of this proceeding.

³ Ruling, p. 21-22.

target customers willing to invest in the necessary BTM technologies or to the ratepayers who would be funding the incentives.

Customer response to organic rate design, such as to existing Time-Of-Use rates or to anticipated dynamic rate structures, is generally beneficial provided that the rates are an accurate reflection of marginal costs. However, beyond this voluntary response, it is unknown if the costs of providing and maintaining the communication systems necessary for the Distribution System Operator (“DSO”) to issue import and export limits to customers with controllable DERs will be offset by benefits to participating customers and to the funding ratepayers. Realization of these benefits requires that programs be defined, cost-effective incentives and compensation mechanisms identified and developed, contracts and tariffs promulgated and approved, and payment/settlement systems implemented. The Ruling’s questions may provide useful information in terms of the current status of Advanced Distribution Management Systems (“ADMS”)/Distributed Energy Resources Management Systems (“DERMS”), but they lack the foundational elements of program definition and commercial viability. The Ruling’s questions place the technological cart before the financial horse.

With respect to technology, the Ruling contains confusing references to polyphase locations. There is a difference between producing variable operating envelopes for all locations on the polyphase distribution grid versus producing variable operating envelopes for all polyphase customers. Unfortunately, the Ruling uses these terms interchangeably, creating uncertainty as to the intended signaling locations. A three-phase distribution circuit serves many customers, including customers connected by three-phase service and customers connected by single-phase service. Polyphase customers, however, refers only to the subset of customers that take three-

phase service.⁴ Using the terms “polyphase distribution grid” and “polyphase customers” interchangeably can lead to misunderstandings about the modeling and analytical capabilities required to implement the measures outlined in the Ruling. There are significant locational differences between the two terms which may drive consequential distinctions in signaling technologies and costs.

On the modeling side, which forms the foundation for all analytical outputs, including forecasts and operating envelopes, SDG&E currently maintains Geographic Information System (“GIS”) based models representing the distribution infrastructure. These models include both three-phase and single-phase lines. However, SDG&E does not maintain a complete model of its secondary networks and does not model individual customers.

On the analytics side, with limited exceptions, SDG&E does not have real-time or high-precision operational data from individual customers, whether single-phase or three-phase. Currently, Automated Metering Infrastructure (“AMI”) data is aggregated at the service transformer level and loaded into the DMS to be used in ADMS applications, fed into the power flow model for distribution circuits, and calibrated against real-time Supervisory Control and Data Acquisition (“SCADA”) data from the respective circuits to produce power flow results for the primary lines and infrastructure. While this level of data has proven acceptable for reliably operating the distribution grid, it is insufficient for providing short-term power flow forecasts for all segments of a distribution circuit and for developing associated short-term maximum import/export limits (“operating envelopes”) at the individual customer level at this time. The goal of providing “operating envelopes” to either single phase customers or three phase customers

⁴ For purposes of responding to the Ruling’s questions, the term “customers” is understood to include both (i) Behind-The-Meter (“BTM”) entities with retail loads, some of which may have on-site generation resources, and (ii) In-Front-of-the-Meter (“IFM”) entities owning resources that are interconnected directly to the distribution grid. Both sets of customers include customers taking three-phase service and customers taking single-phase service.

would introduce the complicated design around how to “allocate” capacity among the customers served by common assets.

For customers with generation, SDG&E is only permitted by tariffs to require the customer to provide real-time data if the generator is larger than 1 MW. This limitation further prevents accurate calculation of operating envelopes, which would require precise knowledge of real-time load and generation at each service point.

It remains unclear whether the Commission’s questions assume operating envelopes will be developed for every customer taking three-phase service or for “all” locations on three-phase distribution circuits. The former would require significant investment in data acquisition and modeling, while the latter would not provide meaningful customer-level insights, as multiple customers are jointly served at many locations along a three-phase distribution circuit. Additionally, for each approach, there is no clear discussion regarding how customer participation, consent, responsibilities, and required technological investments will factor into implementation. Calculating potential operating envelopes is one step; designing an architecture to operationalize them is an entirely different level of complexity. Such a system would need to issue envelopes to customers, allow acceptance or rejection, immediately revise forecasts and envelopes based on customer responses, produce updated operational envelopes in near real time and confirm customer compliance with the signaled maximum import/export limits. This process is challenging even on a day-ahead basis and becomes significantly more complex when envisioned as a dynamic, continuous implementation. Furthermore, utilities would need to significantly scale resources, not only to design, implement, and administer such a program, but also to provide customer service and technical support.

Below, SDG&E submits its responses to questions 1-15, 19, 21 and 22 set forth in the Ruling. For ease of reference, SDG&E uses the same format and numbering convention (including the subpart numbering) presented in the Ruling.

Questions and Direction for Large IOU Response Regarding ADMS/DERMS Capabilities that Unlock Non-Firm Capacity for Polyphase Customers

1. Are IOU ADMS and DERMS currently capable of providing short-term (e.g., day-ahead or week-ahead) load and generation capacity forecasts suitable for variable operating envelopes for all locations on the polyphase distribution grid?

SDG&E has, on a test basis, demonstrated the ability of its ADMS to generate short-term power flow forecasts. However, this ADMS feature cannot currently be scaled to the production level without materially comprising processing speeds for core distribution operation functions.

Through a pilot project, SDG&E is initially targeting development of ADMS capability to calculate dynamic charging limits for storage resources connected to SDG&E's distribution system under the Wholesale Distribution Access Tariff ("WDAT"). Expanding the ability to provide import and export limits to "all locations" on the three-phase distribution grid as contemplated by the question, is not practical at this time.

Further, besides the ability to calculate the limits, SDG&E does not have SCADA devices at "all locations" or the supporting communication architecture to provide these limits to customer owned resources. These devices are typically used to relay electronic signals to customers connected to the distribution system and to generators interconnected with the distribution system. Absent programs under which connected entities would limit their imports or exports in order to provide services to the utility, and subsequently the entities electing to participate in those programs, it would be premature to install SCADA devices at "all locations."

While SCADA is not strictly required for the forecasting module to run, SDG&E has completed limited internal testing to understand how the ADMS power flow engine performs in producing load and generation forecasts. These tests were exploratory and were not intended to

serve as operational forecasting pilots. However, locations without SCADA or other reliable telemetry have significantly reduced forecast accuracy, and the existing production environment cannot support the data processing and computational requirements that would be needed for short-term forecasting across the system. Furthermore, as noted in the opening section of these comments, if the expectation is to produce load and generation forecasts at the customer level, additional modeling and enhanced telemetry at that level will be required to enable these capabilities.

Expansion of forecasting capability to include circuit level and DER inclusive forecasts is expected to occur as part of future DERMS deployment and associated system modernization work. SDG&E is currently prioritizing foundational readiness activities that include improving AMI data integration, validating DER and load modeling within ADMS, and aligning data quality across all data sources. These steps are needed before any short-term forecasting functionality can be operationalized. SDG&E will continue to build the underlying data structures and system capabilities necessary for forecasting functionality as part of the planned DERMS program and supporting IT and OT enhancements.

- e. If ADMS and DERMS are currently capable of providing short-term forecasts for variable operating envelopes, what is the maximum number of locations that can be forecast at the normal duration (e.g., day-ahead or week-ahead) with the current or planned level of resources?**

Current capabilities are limited to small-scale proof of concept initiatives or feeder level applications. Reliable forecasting granularity does not yet extend to all service locations. Scaling up would require additional computing power, data integration, and vendor tool enhancement.

- f. For ADMS and DERMS that are not currently capable of providing short-term forecasts, what other systems or manual processes have been used (e.g., in research projects, pilots, or demonstrations) to provide this capability?**

Additional functionality is required for data ingestion, forecasting accuracy, and scalability. Specific gaps include behind the meter telemetry integration, AMI data

harmonization, DER model calibration for non-weather-based DERS, and automation of forecast validation. Resourcing would involve data engineering, vendor enhancements to ADMS/DERMS forecasting modules, and cross-system integration with enterprise systems.

- g. For ADMS and DERMS that are not currently capable of providing short-term forecasts, what is the planned timeline for developing this capability? Please note if this timeline differs from the timeline presented in the most recent IOU filing (e.g., Operational Flexibility or Bridging report, GRC [General Rate Case] work paper, etc.).**

SDG&E is pursuing incremental functionality through proof-of-concept initiatives and ADMS/DMS vendor coordination. Near-term customer solutions will rely on existing feeder-level long-term forecasting tools and planning models until advanced DERMS functions are deployed. Timelines remain dependent on factors such as vendor roadmaps and the availability of funding.

- 2. Are IOU ADMS and DERMS currently capable of rapidly providing load and generation forecasts suitable for dynamic operating envelopes (e.g., hour ahead values) for all locations on the polyphase distribution grid?**

Currently ADMS configurations do not produce hour-ahead or sub-hourly forecasts suitable for dynamic operating envelopes. The existing systems leveraged by WDAT assets operate with static or scheduled parameters. Real-time or rapid forecasting capabilities are under conceptual evaluation as part of future DERMS design and integration planning.

- a. If ADMS and DERMS are currently capable of rapidly providing forecasts suitable for dynamic operating envelopes, what is the maximum number of locations that can be forecast at the normal duration (e.g., hour ahead) with the current or planned level of resources?**

No enterprise-level forecasting at this rapid cadence currently exists. Any potential hour-ahead forecasting, if pursued would be limited to pilot-scale circuits or test environments following initial DERMS deployment. Scaling beyond that would require enhanced data availability, computational resources, and refined forecasting models

- b. For ADMS and DERMS that are not currently capable of rapidly providing short-term forecasts suitable for dynamic operating envelopes, what is the planned timeline for developing this capability? Please note if this timeline differs from the timeline presented in the most recent IOU filing (e.g., Operational Flexibility or Bridging report, GRC work paper, etc.).**

Development of rapid (hour-ahead) forecasting capability is planned as a later-stage DERMS function, building upon day-ahead forecasting enablement. Current projections place this functionality towards the late 2020's consistent with DERMS integration phase and depend on data latency improvements and telemetry expansion.

- 3. Please articulate with specificity, as needed, any additional functionalities that must be developed for ADMS and DERMS to be capable of providing short-term load and generation capacity forecasts to all customers located on the polyphase grid of the Large IOUs.**

To support short-term load and DER forecasting grid-wide, additional functionalities are required in several areas: (1) expanded AMI data integration at higher progressive resolution; (2) ingestion and validation of behind-the-meter DER telemetry; (3) improved DER device and fleet modeling; (4) forecasting algorithm enhancements to support technology-specific profiles; (5) historical data warehousing for training and model validation; and (6) ADMS-DERMS interoperability features for forecasting distribution across all operational systems.

- c. If needed, please articulate with specificity any planned or anticipated resources that will be required for these additional ADMS and DERMS functionalities.**

Required resources may include cross-functional data engineering support, vendor-led development of DERMS forecasting modules, subject matter expertise for DER model calibration, expanded cloud or on-prem computing resources, and program management aligned with GRC budgeting. Resource levels will scale with DER penetration and data readiness.

4. With the understanding that the Large IOUs are at different stages of implementing their ADMS and DERMS capabilities, how can the Commission ensure that near-term solutions are provided to customers in a timely fashion?

It is not clear what problems the near-term “solutions” referenced in this question are intended to address.⁵ Absent clear identification of the problems that import and export limits address, and the programs under which customers would agree to such limits, it is premature to consider measures to ensure “solutions” are provided, timely or otherwise.

SDG&E is currently focused on establishing the foundational data, modeling, and system readiness required to support future short-term forecasting and dynamic operating envelopes capabilities. While conceptual designs and interval planning for proof-of-concept initiatives activities have begun, SDG&E has not yet deployed operational forecasting initiatives due to current ADMS/DMS system limitations. Including compute capacity and architectural constraints that prevent large-scale or high-frequency forecast processing. In the near term, SDG&E is directing efforts toward preparing the underlying infrastructure and data pathways so future pilot projects and incremental forecasting capabilities can be executed reliably. These steps include AMI data improvements, DER modeling validation, data quality enhancements, and alignment of IT/OT interfaces necessary for eventual DERMS integration. This preparatory work ensures that once DERMS capabilities begin deployment, SDG&E can transition quickly into functional pilots and expand forecasting without significant rework.

d. Please provide an estimated timeline for how long it would take to implement these solutions.

As previously stated, SDG&E notes that the Ruling does not clearly identify the specific problems these “solutions” are intended to address. Without a defined program framework,

⁵ SDG&E understands that the questions are not asking about “bridging strategies.” Import limits are useful for providing an interim mechanism for partially energizing loads in situations where distribution infrastructure cannot be put in place in time to fully energize a customer’s load. To date, SDG&E has not needed bridging strategies.

prescribing timelines for implementation would be premature. Nevertheless, SDG&E is actively advancing foundational data and system readiness activities. These efforts will continue through 2025–2027 and include the prerequisites needed for pilot-scale forecasting use cases. Once the DERMS platform is procured and integrated (currently planned for 2027-2028), SDG&E expects to begin the conceptual proof-of-concept initiatives into executable operational pilots. Therefore, near-term foundation work is currently ongoing (2025-2027), with pilot-capable environments expected to emerge as DERMS infrastructure is established (post 2027). Full operational functionality would follow DERMS deployment and system maturation.

5. If needed, what solutions should the Large IOU(s) at an earlier stage of ADMS/DERMS capabilities employ as interim measures as their ADMS/DERMS capabilities are building up?

SDG&E does not currently use operational interim tools for short term or dynamic forecasting. Existing ADMS tools in production are not configured to support forecasting in a day ahead or hour ahead context. Currently SDG&E relies on long term planning information that is intended for multiyear or seasonal studies. This information is not granular enough and not designed for day-to-day operational forecasting.

Because the current production environment cannot support the data processing and computational loads required for concept level forecasting pilots, SDG&E is concentrating on foundational readiness work. This includes preparing AMI data for future forecasting uses, validating DER and load models within the ADMS environment, improving data quality and consistency across all data sources, and preparing system interfaces that will be required once a DERMS platform is deployed.

These foundational activities represent the most practical and technically achievable interim measures for SDG&E at this stage of ADMS and DERMS maturity.

- a. Please provide an estimated timeline for how long it would take to implement these solutions.**

Since SDG&E is not deploying operational interim forecasting tools at this time, the timeline reflects the duration of foundational readiness work rather than the deployment. Data quality enhancements, AMI data integration improvements, DER model validation effort, and the necessary architectural preparation are expected to continue through the 2025-2027 period.

The ability to introduce pilot scale forecasting capabilities depends on the completion of these prerequisites along with the integration of the planned DERMS platform. The DERMS integration period is currently expected to occur between 2027-2028. Once these upgrades are in place, SDG&E anticipates that the system environment will be capable of supporting more advanced forecasting activities.

- 6. Is there a limitation on the number of customers that can be provided day ahead variable operating envelopes (based on these short-term forecasts) through the Large IOUs' IEEE 2030.5 communications servers?**

A DERMS head-end server has not yet been selected, so any specific limit on the number of customers that can be provided day-ahead variable operating envelopes through IEEE 2030.5 servers or other communication mechanisms is unknown at this time. These considerations will be evaluated during the ongoing DERMS procurement process.

- 7. Is there a limitation on the number of customers that can be provided dynamic operating envelopes (based on an assumption of hour ahead forecasts) through the Large IOUs' IEEE 2030.5 communications servers?**

Please see SDG&E's response to question 6.

- 8. Are there any communication functionalities required to provide variable or dynamic operating envelopes to customers on the polyphase electric grid that are not provided by the IOU CSIP/IEEE 2030.5 [Common Smart Inverter Profile/IEEE 2030.5] infrastructure?**

A communication mechanism for variable or dynamic operating envelopes has not yet been assessed; therefore, the requirements remain undefined at this time. These considerations will be addressed as part of the ongoing IEEE 2030.5 testing.

9. Please detail with specificity any plans, including projected timelines, to bring down the customer cost to receive variable or dynamic operating envelopes via direct communications⁶ with IOU IEEE 2030.5 servers.

SDG&E has no current plans specifically targeted at reducing customers' costs of receiving electronic signals from SDG&E, via direct communication with IEEE 2030.5 compliant servers, to limit the customer's imports or exports.

10. Are there any existing arrangements with aggregators that would allow those aggregators to coordinate the response of multiple customers?

Today, any aggregator which wants to aggregate loads and bid those loads into the CAISO market, as well as be compensated for that load reduction by SDG&E, can engage in an agreement with SDG&E through SDG&E's tariffed Capacity Bidding Program (or other IOU program approved by the Commission such as the Emergency Load Reduction Program ("ELRP")). Such aggregators coordinate the response of multiple customers who must meet eligibility requirements. However, SDG&E does not have insight into the communications between the aggregators and the customers. Further, SDG&E does not have knowledge of demand response programs for customers of Energy Service Providers and/or Community Choice Aggregators ("CCA"), and does not know whether these commodity providers employ the services of aggregators.

11. Please detail with specificity any plans, including projected timelines, for IOUs to enter into agreements with aggregators⁷ that would reduce the per customer cost to receive variable or dynamic operating envelope data from IOU ADMS and DERMS.

⁶ PG&E February 28, 2025 OpFlex Pilot Report at 23, "generally it is expected these costs to be in the \$20k-\$50k range."

⁷ <https://www.pge.com/assets/pge/docs/about/doing-business-with-pge/TD-2306P-01.pdf>, accessed on October 12, 2025; PG&E's COT [Customer Owned Telemetry] lists the cost of integration with their 2030.5 system as \$4,000, not including the customer side hardware, installation, and communications costs.

At present SDG&E has no plans for specific incremental offerings to aggregators since its current programs are approved through 2027. Accordingly, in the near term, SDG&E has no plans for aggregator agreements under which the per-customer cost to transmit import and/or export limits would be reduced.

Notably, there remains uncertainty regarding potential agreements that pertain to the control of customer loads. The Commission has opened a new rulemaking for demand response with comments on the scoping memo submitted on November 13, 2025. The IOUs are to file their next demand response applications in 2026 for program years 2028 through 2032. These applications will include associated budgets. It is unknown if the demand response rulemaking schedule will delay or otherwise impact the IOUs' applications. Note that any proposed demand response program, including offerings to aggregators, would need to be cost effective (i.e., demand response must be cost effective in the IOUs' applications).

12. Please detail with specificity the level of data that is provided to Community Choice Aggregators about large customers within your service territory.

Per the rules outlined in Schedule CCA-INFO, any CCA or eligible entity under Public Utilities Code ("PUC") Section 331.1 that is considering CCA service may request the information described in A and B below. This information is made available to any eligible entity upon request. The information described in C, D and E below are provided to the active CCAs in SDG&E's service territory as part of ongoing business operations; it applies to all customers, not just large customers:

- A. Information Available At No Charge
 - 1. Proportional share of energy efficiency funds for a CCA's proposed territory, as defined in the Commission's energy efficiency policy manual
 - 2. Public Goods Charge customer payments by city code
 - 3. Most recent 5-year average coincident load factors by rate class
 - 4. Most recent 5-year average non-coincident load factors by rate class
 - 5. Mapping of customer rate schedule to rate class

B. Information Available for a Fee

1. Aggregate annual usage (kWh) by customer class, rate class, city code, rate schedule, zip code, and climate zone
2. Aggregate monthly usage (kWh) by customer class, rate class, city code, rate schedule, zip code, and climate zone
3. Number of accounts in each rate schedule within the CCA's service area
4. Direct Access vs. bundled aggregate annual usage by customer class and city code
5. Direct Access vs. bundled monthly usage by rate class
6. Non-Residential Customer specific information consisting of account name, account number, service address, mailing address, and e-mail address for all accounts, within the CCA's service area
7. Customer specific information: account number, meter number, monthly kWh usage, time-of-use (TOU) usage consumption and maximum monthly demand (where applicable), billing days, and rate schedule, for all accounts within the CCA's service area
8. Customer specific information: previous 12 months interval meter data, account number, rate schedule, for all accounts within the CCA's service area
9. Residential customer specific information consisting of account name, account number, service address, mailing address, e-mail address, for all accounts, within the CCA's service area

Information Provided With Ongoing Billing Operations

C. Reconciliation File

SDG&E provides a weekly Reconciliation file ("recon report") to the CCAs as part of ongoing operations. The recon report does not contain meter interval data but does include almost every other item related to a customer's account that is needed or has been requested by one of the two regional CCAs.

D. Billing Interval Data

SDG&E sends customer usage data to the CCAs for billing purposes via the standardized "Electronic Data Interchange" ("EDI") format. EDI is a standardized system for exchanging business documents electronically between financial institutions and their commercial clients. The EDI 867 transaction set is used to communicate electric meter usage data; data for individual customer accounts is sent to the CCAs for their use in calculating charges based on their commodity rates. The data contains either 15-minute or 60-minute interval data, depending on the customer. SDG&E also transmits cumulative monthly values for customers not billed on interval rates. At the time of monthly billing, an 867 EDI transaction is triggered to send the interval or cumulative billing data for the account.

E. Interval Data On Demand

Customer-level consumption data is provided to the CCAs in near-real time via a data solution that was developed specifically for CCAs at their request. CCAs are able to

directly query and access 15- or 60-minute interval data for their customers within 48-72 hours of usage. This “data lake” provides the most current interval data available. In cases where a meter is not communicating, then estimated data is provided.

13. Should Rules, Tariffs, or policies be modified in order to allow for the implementation of variable or dynamic operational envelopes for customers on the polyphase grid?

SDG&E recognizes that enabling the use of variable or dynamic operational envelopes under a standardized structure may require future modifications to rules, tariffs, and policies. These changes would likely address contractual obligations, incentive structures, and cost recovery mechanisms necessary to support customer engagement and ensure regulatory compliance.

a. If yes, please provide suggestions regarding the specific Rules, Tariffs, or policies, and any suggested modifications.

At this time, SDG&E has not identified specific rules, tariffs, or policies that require modification to implement variable or dynamic operational envelopes. Such an effort depends on a coordinated framework informed by program design and customer participation.

b. If no, what Commission guidance and IOU action is needed in order to implement variable or dynamic operational envelopes?

Rules and tariff provisions governing the contractual obligations of customers and the utility, including compensation, would require the IOUs to develop proposed language, program design, incentive levels and associated budgets for cost recovery, and for the Commission to act on those proposals. If such proposals are treated as demand response, then they must be aligned with Commission demand response policies regarding dual participation, CAISO rules, and also be cost-effective using the approved demand response protocols used to determine cost-effectiveness. If this is to be done as a pilot, under grid modernization, then the proposals would still need to be Commission-approved, with an

associated budget, but there could be some flexibility of taking action outside of the demand response portfolio (e.g., offering it as a pilot which removes the need to be cost-effective, etc.).

Questions for Large IOUs Regarding Directed Maximum Capacity Values during Abnormal Grid Operation

- 14. Please estimate the annual number of abnormal grid operations due to emergent situations which utilize operational flexibility actions such as switching or curtailment to ensure reliable operation.**

Based on the average number of completed work from 2022–2024, SDG&E estimates approximately 4,180 abnormal grid operations annually due to emergent events. SDG&E does not have the data readily available to specify which abnormal grid operations utilized operational flexibility actions. Additionally, SDG&E notes that the total number of abnormal grid operations does not imply that every switching plan performed would necessarily benefit from the existence of dynamic operating envelopes.

- 15. Please estimate the annual number of abnormal grid operations due to planned events which require utilize operational flexibility actions such as switching or curtailment to ensure reliable operation.**

Based on the average number of completed work from 2022–2024, SDG&E estimates approximately 16,645 abnormal grid operations annually due to planned events. SDG&E does not have the data readily available to specify which abnormal grid operations utilized operational flexibility actions. Additionally, SDG&E notes that the total number of abnormal grid operations does not imply that every switching plan performed would necessarily benefit from the existence of dynamic operating envelopes.

Questions for Parties Regarding Directed Maximum Capacity Values during Abnormal Grid Operation

- 16. Does the value provided by the ability to signal maximum import values via IEEE 2030.5 to sites on the polyphase grid during emergent abnormal grid operation justify the technical and contractual effort necessary to develop this ability?**

- c. **How could such customer import direction be developed and implemented to maximize value and produce significant net benefit to the system?**
17. **Does the value to the system provided by the ability to signal maximum import values via IEEE 2030.5 to sites on the polyphase grid in anticipation of potential or planned abnormal grid operation justify the technical and contractual effort necessary to develop this ability?**
18. **Should Rules, Tariffs, or policies be modified in order to allow for operator signaled maximum import capacity limits under abnormal grid operation?**
- d. **If yes, please provide suggestions regarding the specific Rules, Tariffs, or policies, and any suggested modifications.**
 - e. **If no, what Commission guidance and IOU action is needed in order to allow for operator signaled maximum import capacity limits under abnormal grid operations?**
 - f. **Please describe what implementation considerations may differ between signaled response to emergent abnormal conditions and operating envelope adjustment in response to planned abnormal conditions.**

Questions Regarding Flexible Capacity for Single Phase Feeder Customers

19. **Approximately what portion, in quartiles (e.g., 0-25%, 25-50%) of the Large IOU single phase customers have their service infrastructure modeled in power flow software?**

SDG&E understands the inquiry to pertain to whether the service infrastructure supplying customers is presently represented in its power flow analysis software. In response, the representation rate is 0%. SDG&E does model all single-phase distribution lines in its system model, the phasing designations may not always be fully accurate.

20. **Do parties favor adapting existing approaches (e.g., LLL [Load Limit Letter], FlexConnect) to serve single phase customers, or taking a different approach?**
- g. **If parties favor a mix of adaptation and different approaches, please detail which elements (e.g., computing static operating profile, communicating day ahead values, etc.) should be adapted and which should use a different approach.**
21. **Are there any existing plans to expand ADMS and DERMS load and generation forecasting capabilities to single phase customers?**
- a. **If yes, please detail these plans.**
 - b. **If no, what is the reason for not pursuing inclusion of these portions of the grid?**

The development of SDG&E's short-term load/generation forecasting capabilities is independent of whether a customer is connected three-phase or single phase. However, including single-phase customers in the program design significantly increases the project's complexity and scale. It would increase the modeling, data and computing needs significantly.

22. Is there a lower cost communication pathway that can be leveraged to provide lower frequency⁸ and longer response time⁹ communication of short-term profile values to DER customers taking single phase service?

IEEE 2030.5 currently uses 15-minute intervals, which is considered low frequency.

Lower-cost options could include cellular IoT (LTE-M, NB-IoT) or shared broadband, as they support longer response times and lower bandwidth needs. Selection should prioritize cost, reliability, and security.

23. Should the Commission pursue non-bridging flexible connections as a way for single phase customers to avoid or defer grid upgrades? Please provide details as to how this could be implemented.

24. What current models or methodologies (e.g., AusNet Approximation algorithm, Asset Capacity Operating Envelopes, LV [Low Voltage] network approximation with AMI [Automated Metering Infrastructure] data, etc.) have the potential to provide low-cost static or variable operating envelopes for the purpose of minimizing or deferring distribution line or service upgrades on single phase feeders?

25. Are there power control systems or smart inverter functions (e.g., voltage support or reactive power) that should be leveraged to maximize the available load and generation capacity for these low-cost options?

- a. If yes, are there existing solutions that can be quickly implemented without relying on ADMS/DERMS and communications?**
- b. If yes, should we prioritize these solutions in addition to focusing on larger customers?**

⁸ PG&E currently communicates with FlexConnect customers at least once per day.

⁹ Operational Flexibility events triggered under the Operational Flexibility functionality of the FlexConnect pilot have demonstrated responses on the order of 30 seconds.

26. Are there aggregators/equipment manufacturers that have the capability to coordinate the power use of multiple single phase customer sites connected to shared infrastructure such that capacity can be safely shared within that infrastructure?
- c. If yes, what steps would be required to prove and scale the coordinated control of multiple sites for safe flexible connections?
27. Should Rules, Tariffs, or policies be modified in order to allow for the implementation of static or variable operational envelopes for single phase customers?
- a. If yes, please provide suggestions regarding the specific Rules, Tariffs, or policies, and any suggested modifications.

Questions and Direction for Parties Regarding Dynamic Rates for Customers Utilizing Dynamic and Variable Operating Envelopes

28. Should existing and new customers utilizing variable or dynamic operating envelopes be required to enroll in dynamic rate pilots, when available in their territory, and then be defaulted to dynamic rates when the pilots are no longer available? Please provide rationale for your response.

III. CONCLUSION

SDG&E appreciates the Commission's careful review and consideration of its comments on these issues. SDG&E values the opportunity to contribute to the ongoing discussion of Track 3 issues in this proceeding and looks forward to continued collaboration to develop effective policies that benefit both customers and the broader energy system.

Respectfully submitted,

/s/ Roger A. Cerda

Roger A. Cerda
8330 Century Park Court, CP32D
San Diego, CA 92123
Telephone: (858) 654-1781
E-mail: rcerda@sdge.com

Attorney for:
SAN DIEGO GAS & ELECTRIC COMPANY

November 25, 2025