STAFF PROPOSAL FOR THE HIGH DER PROCEEDING

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CALIFORNIA PUBLIC UTILITIES COMMISSION
ENERGY DIVISION

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ACRONYMS & DEFINITIONS

ACRONYMS

AADT: Annual Average Daily Traffic

AAEE: Additional Achievable Energy Efficiency

AAFS: Additional Achievable Fuel Switching

AB: Assembly Bill

AC: Alternating Current

ACC II: Advanced Clean Cars II

ACF: Advanced Clean Fleets

ACR: Assigned Commissioner Ruling

ACS: American Community Survey (U.S. Census Bureau)

ALJ: Administrative Law Judge

AMI: Advanced Metering Infrastructure

AUC ROC: Area Under the Receiver Operating Characteristic Curve

BA: Balancing Authority

BE: Building Electrification

BESS: Battery Energy Storage System(s)

BEV: Battery Electric Vehicle

BTM: Behind-the-Meter

C&I: Commercial and Industrial

CAISO: California Independent System Operator

CARB: California Air Resources Board

CARE: California Alternate Rates for Energy

CAVA: Climate Adaptability Vulnerability Assessment

CBECS: Commercial Buildings Energy Consumption Survey

CCA: Community Choice Aggregator

CEC: California Energy Commission

CEDARS: California Energy Data and Reporting System

CPUC: California Public Utilities Commission

CSF: Competitive Solicitation Framework

C-TERA: California Tribal Energy Resilience Alliance

D: Decision

DAC: Disadvantaged Community

DC: Direct Current

DCFC: Direct Current Fast Charging

DDOR: Distribution Deferral Opportunity Report

DER: Distributed Energy Resource

DERMS: Distributed Energy Resource Management Systems

DGEM: Distribution Grid Electrification Model

DIDF: Distribution Investment Deferral Framework

DMDU: Decision-Making under Deep Uncertainty

DOE: U.S. Department of Energy

DP: Distribution Planning

DPAG: Distribution Planning Advisory Group

DPEP: Distribution Planning and Execution Process

DPP: Distribution Planning Process

DRPTMA: Distribution Resources Plan Tools Memorandum Account

EDGE: EVSE Deployment and Grid Evaluation

EE: Energy Efficiency

EIS: Electrification Impact Study

EV: Electric Vehicle

EVI-Pro: Electric Vehicle Infrastructure Projection Tool

EVSE: Electric Vehicle Service Equipment

EVSP: Electrical Vehicle Service Provider

FIP: Freight Infrastructure Planning

FTP: File Transfer Protocol

FTM: Front-of The-Meter

GHG: Greenhouse Gas

GIS: Geographic Information System

GNA: Grid Needs Assessment

GRC: General Rate Case

GVWR: Gross Vehicle Weight Rating

HD: Heavy Duty

HDV: Heavy-Duty Vehicle

HEIAWG: High Electrification Inter Agency Working Group

ICA: Integration Capacity Analysis

ICE: Internal Combustion Engine

IEPR: Integrated Energy Policy Report

IOU: Investor-Owned Utility

IRP: Integrated Resource Plan

JASC: Joint Agency Steering Committee (CPUC, CEC, CAISO, CARB)

kV: Kilovolt

KVA: Kilovolt-Ampere

kW: Kilowatt

kWh: Kilowatt-Hour

L1: Level 1

L2: Level 2

LATCH: Local Area Transportation Characteristics for Households Data

LD: Light Duty

LDV: Light-Duty Vehicle

LGP: Limited Generation Profiles

LOR: Load Offset Ratio

LSE: Load-Serving Entity

MD: Medium Duty

MDV: Medium-Duty Vehicle

MLR: Multilevel Logistic Regression

MSS: Mobile Source Strategy

MUD: Multi-Unit Dwelling

MVA: Megavolt-Ampere

MW: Megawatt

MWh: Megawatt-Hour

NAICS: North American Industry Classification System

NEM: Net Energy Metering

NREL: National Renewable Energy Laboratory

NSRDB: National Solar Radiation Database

NWA: Non-Wires Alternative

OIR: Order Instituting Rulemaking

PCIA: Power Charge Indifference Adjustment

PEV: Plug-in Electric Vehicle

PG&E: Pacific Gas and Electric

PHEV: Plug-in Hybrid Electric Vehicle

PII: Personal Identifiable Information

PR AUC: Precision Recall Area Under the Curve

PV: Photovoltaic Solar Energy System

R: Rulemaking

RASS: Residential Appliance Saturation Study

RCP 8.5: Representative Concentration Pathway 8.5

SB: Senate Bill

SCADA: Supervisory Control and Data Acquisition

SCE: Southern California Edison

SDG&E: San Diego Gas & Electric

SIP: State Implementation Plan

SSS: State SIP Strategy

SUD: Single-Unit Dwelling

SUV: Sport Utility Vehicle

T&D: Transmission and Distribution

TAC: Transmission Access Charge

TB: Terabytes

TE: Transportation Electrification

TEGR: Transportation Electrification Grid Readiness

TO: Transmission Owner

TOU: Time-of-Use

TPP: Transmission Planning Process

TPR Process: Transmission Planning Review Process

U.S.: United States

UEC: Unit Energy Consumption

VIO: Vehicles in Operation

VIUS: Vehicles in Use Survey

VMT: Vehicle Miles Traveled

ZEV: Zero-Emission Vehicle

DEFINITIONS

8760: Generally refers to the number of hours in a typical (non-leap) year.

Actual In Service Date: The date which the infrastructure is actually energized.

Adoption model: A model that predicts the consumer's likelihood to adopt a new technology. The model considers multiple variables that can reliably predict the consumer's ability and willingness to adopt a new technology such as the characteristics of early adopters, factors that drive market potential, and historical adoption rates.

Adoption propensity score: The output from the adoption model. It is a measure of the rank of a customer's likelihood to adopt relative to all other customers.

Advanced metering infrastructure (AMI): A time-series energy consumption data measurement and collection system that includes advanced meters/smart meters at the customer site, communication networks between the customer and utility, and data collection and management systems that make the information available to the utility, customer, and authorized third-party vendors.

Area under the receiver operating characteristic curve (AUC ROC): This metric summarizes performance over all adoption thresholds and is designed to quantify how well a model is able to separate adopting premises from non-adopting premises. AUC ROC quantifies how a model performs on the tradeoff between the true positive rate (e.g., predicting adoption at a premise where adoption actually occurred) and the false positive rate (e.g., predicting adoption at a premise where adoption did not actually occur).

Battery electric vehicle (BEV): Also known as an all-electric vehicle, BEVs use energy that is stored in rechargeable battery packs. BEVs sustain power through the batteries and must be plugged into an external electricity source to recharge.

Bayesian: An approach to statistical inference that combines prior information about the distribution of an unknown value with posterior evidence from information contained in a sample. In data science, it is a popular technique for building models when labeled ground truth data is relatively limited, but there is subject matter understanding to build upon.

Behind-the-meter (BTM): BTM refers to customer-sited distributed energy resources (DERs) such as solar PV or battery storage that are connected to the distribution system on the customer's side of the utility's service meter.

Behind-the-meter (BTM) tariff: A set of rate structures (energy based, demand based, or customer charge) and components (costs related to generation, delivery, transmission, and other costs) that apply to customers with DERs.

Bottom-up forecast: A bottom-up method forecasts the generation and load impact from distributed energy resources (DERs) based on adoption models while considering the characteristics of early adopters, factors that drive market potential, and adoption rates applied to the remaining potential customers. The forecast is predicted at a granular level (i.e., at the customer premise level).

Building electrification (BE): Refers to the electrification of appliances and equipment in buildings (e.g., electric heat pump replacing gas heating, electric water heaters replacing gas water heaters, electric cooktops replacing gas cooktops). Electrification of appliances and equipment in buildings is also referred to as fuel switching.

California Independent System Operator (CAISO): CAISO is the electric grid operator for California's electrical transmission system.

Coincident peak load: The maximum energy use in an hour compared to all other hours in the year for a collection of loads, such as premises, feeders, or an entire service area. For example, a system coincident peak is the peak of the system for all customers in that system.

Demand modifiers: Refers to the expected hourly behavior from DERs that changes the customer's overall energy use pattern.

Demand response: Refers to any change in net electricity demand made by the customer in response to an economic incentive or grid signal to reduce, increase, or shift net-load relative to what the net-load would have been absent the signal. The change could be temporary or recurring.

Distributed energy resources (DERs): Includes distributed renewable generation resources, energy efficiency measures, energy storage devices, electric vehicles (EVs) and electric vehicle service equipment (EVSE), time-variant and dynamic rates, flexible load management technologies, and demand response technologies. Most DERs are connected to the distribution grid behind the customer's electric meter, and some are connected in front of the customer's electric meter.

Distribution Planning Process: A process, typically done annually, to forecast electric distribution equipment upgrade or improvement needs to maintain safe, reliable, and affordable service while efficiently operating the existing electrical distribution grid.

Electric vehicle service equipment (EVSE): The equipment that interconnects the electricity grid at a site to an EV. Sometimes used more broadly to mean charging station, whether alternating current (AC) or direct current (DC) but not including other behind-the-meter (BTM) charging related infrastructure. EVSE equipment is classified as:
*Level 1 (L1):120 volts AC
*Level 2 (L2): 240 volts, AC
*DC fast charger (DCFC): 480 volts DC and higher

Energy burden: Percent share of the electricity bill costs, potentially also including cost of other energy purchases like natural gas and gasoline, with respect to the household income.

Fleet EV: Fleet EVs are zero-emission vehicles owned by or registered to an entity (not an individual) and are used for business-related purposes. Fleet EVs can be LDVs, MDVs or HDVs. Fleet EVs only have BEV powertrains and can be one of 10 vehicle classes.

Forecast: A prediction or estimate of future electricity demand based on historical data, current and emerging trends, technology, policy, and data analysis. The IEPR is the standard statewide forecast that "conducts assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices."

Forecast In Service Date: At the current time, the date by which the infrastructure is expected to be constructed and energized, considering available resources, project life cycles, and exogenous factors (e.g. licensing and permitting).

Forecasting Horizon: How far into the future load growth is estimated. It publishes expected load growth over time. The IEPR is the standard statewide load growth forecast, and it has a forecast horizon of 15 years. For distribution planning purposes, the forecast horizon is how far into the future the IEPR is analyzed to identify grid needs.

Grid integration: The practice of developing efficient ways to deliver variable renewable energy to the grid. Robust integration methods look at how to maximize the cost-effectiveness of incorporating variable renewable energy into the power system while maintaining or increasing stability and reliability.

Gross vehicle weight rating (GVWR): The gross vehicle weight rating of a vehicle is the maximum allowable weight of the fully loaded vehicle (including passengers and cargo), as rated by the automobile manufacturer.

Integrated Energy Policy Report (IEPR): California Senate Bill (SB) 1389 requires the California Energy Commission (CEC) to conduct assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices. The CEC adopts an IEPR every two years and an update every other year. The energy and DER forecasts produced in the IEPR are used in the California utilities' Distribution Planning Process.

Integrated Resource Plan (IRP): A procurement plan used by utilities that details what resources are to be procured and how they will be procured to comply with California's climate and energy policies, adequately balance safety, reliability, and cost, while meeting the state's environmental goals described in SB 350 and SB 100.

Mean absolute error: Defined as the sum of absolute errors between predicted and actual values, divided by the sample size. A smaller value is better.

Mean absolute percentage error: Average of the absolute percentage errors between the predicted and the actual values. It quantifies the relative versus the absolute typical difference, but it has limited usefulness if the actual values are near zero, where the mean absolute percentage error tends towards infinity.

Multilevel logistic regression (MLR): Logistic regression is a machine learning algorithm, similar to linear regression but designed to predict a binary outcome with a score in [0.0, 1.0] so that it can be applied to classification problems. A multilevel logistic regression separates the population into clusters before applying a logistic regression to the population belonging to each cluster and may be more effective if the differences between those clusters are consistently more substantial than the differences within the clusters.

Need Date: The date an overload or other issue is predicted to occur on the grid system, based on the distribution planning forecast, and thus the date an associated capital upgrade project to mitigate the issue is needed. The need date could change between years based on updated forecasts.

Net energy metering (NEM): Metering and billing arrangement designed to compensate any generation from DERs that is exported to the utility grid during times when it is not serving onsite load via a bill credit for excess generation.

Net-load: The expected address-level energy use served by the investor-owned utility (IOU) or, in the case of reverse flow, the level of energy the customer is exporting to the grid and the IOU is expected to accept and distribute. It is the sum of actual energy use behind the meter plus or minus the demand-modifying behaviors from DERs.

Node: A transmission node refers to the interface between the distribution and the transmission electric power systems. At transmission nodes, the distribution system is typically represented as an aggregate lumped load in transmission models. Nodes can also be referred to as transmission/distribution interfaces or T-D interfaces.

Non-coincident peak load: The maximum energy use of customers, groups of customers, or grid assets; it does not necessarily coincide with the hour of the coincident peak. For example, a customer's peak load is considered non-coincident as it may differ from the system coincident peak. Similarly, a feeder coincident peak, or the peak on that feeder, may be non-coincident with the system peak. Can also refer to a sum of individual peak loads occurring at different times.

Non-wires alternative (NWA): An electricity grid investment or project that uses non-traditional transmission and distribution (T&D) solutions, such as DERs and load management technologies, to defer or replace the need for specific equipment upgrades, such as transmission lines or transformers.

Order Instituting Rulemaking: Rulemaking proceeding opened by the California Public Utilities Commission (CPUC) to consider the creation or revision of rules, general orders, or guidelines affecting more than one utility or a broad sector of the industry. Comments, proposals, and testimony are submitted by parties to the Order Instituting Rulemaking in written form; oral arguments or presentations are sometimes allowed.

Original In Service Date: The date initially identified from the initial version of the project.

Original Need Date: The need date that was initially identified when the project was first identified.

Original Requested in service date: The first In-service dates for projects for which a specific customer is awaiting service before any modifications or delays.

Peak load: The maximum energy use in an hour compared to all other hours in the year. Peak can be used synonymously with coincident peak, which is the maximum energy use in an hour for a collective group of customers. For example, a system coincident peak is the peak of the system for all customers in that system. Similarly, feeder peak is the peak load for all load connected to that feeder. The individual peaks of customers may differ from the coincident peak and are referred to as non-coincident peaks.

Phase Balancing: The practice of moving load between the three phases in an alternating current grid, so that the phases are evenly balanced. Better balancing of the three phases allows for smoother transmission and distribution of power across the system.

Planning Horizon: How far into the future a workplan is created to address the specific deficiencies identified based on the forecasted load growth. For distribution planning purposes, the workplan includes the specific projects and engineering plans to address the identified deficiencies, or grid needs. These include load transfers, new or upgraded circuits, and new or upgraded substations, among other projects. Utilities typically employ a different planning horizon depending on the level of the upgrade. Distribution line upgrades can be completed in weeks to months and have a planning horizon of 3 years, whereas building a new substation can take 5-10 years and has a planning horizon of up to 10 years.

Plug-in hybrid electric vehicle (PHEV): Vehicles powered by an internal combustion engine (ICE) and an electric motor that uses energy stored in a battery. The vehicle can be plugged into an electric power source to charge the battery. Some can travel nearly 100 miles on electricity alone, and all can operate solely on gasoline (like a conventional hybrid vehicle).

Power charge indifference adjustment (PCIA): A charge or credit to community choice aggregator (CCA) customers that reflects the difference in the portfolio costs for each IOU and the market value of the portfolio. This mechanism is designed to ensure customers are indifferent to receiving services from a CCA versus the incumbent IOU, consistent with legislative requirements. PCIA rates are based on the year the customer moves to a CCA to ensure the departing customer is not responsible for incremental portfolio costs incurred after joining the CCA. These rates that vary based on year are referred to as the “vintage” of the PCIA rate.

Precision: An evaluation metric that measures the adoption model’s ability to identify relevant data points, such as if a customer adopted. It is calculated by taking the number of true positives (number of times an actual adoption was predicted) divided by the number of true positives plus the number of false positives (the number of times an adoption was predicted that was not seen in the base data).

Precision recall area under the curve: The area under the precision recall curve, which is used to assess the performance over all the adoption thresholds as represented by the precision and recall metrics.

Premise: Contiguous geographic area used by a utility to track billing and usage. It contains service points and meters and should have an address assigned to it.

Recall: An evaluation metric that measures the adoption model’s ability to identify all relevant cases within a dataset. It is calculated by taking the number of true positives divided by the number of true positives plus the number of false negatives.

Requested In Service Date: The date the customer indicates they will need to be energized, in-service, ready to do business for their needs. This date can change based on their year-to-year assessments of their plans.

Required In Service Date: The date the capital upgrade project will be energized to mitigate the forecasted overload which is associated to the need date.

Root mean squared error: The square root of the average squared difference between the predicted and actual values. It is similar to mean absolute error, but it is more sensitive to outliers where the prediction was far from the actual value.

Time-of-use (TOU) rate: A rate plan with rates that vary according to the time of day, season, and day type (weekday or weekend/holiday). TOU rates can encourage the efficient use of the system and can reduce the overall costs for the utility and its customers.

Top-down allocation: A method for providing a transmission system-level aggregate load and DER forecast that disaggregates the load and DER forecast to distribution circuits based on utility data for the circuit (e.g., load, energy, or number of customers) or statistical propensity models.

Vehicle duties: A vehicle duty refers to the three duty types that the U.S. Federal Highway Administration uses to categorize vehicles by gross vehicle weight rating (GVWR). The duty types are>
*Light-duty vehicle (LDV): <10,000 GVWR

*Medium-duty vehicle (MDV): 10,001-26,000 GVWR
*Heavy-duty vehicle (HDV): > 26,001 GVWR

Zero-emission vehicle (ZEV): Vehicles that produce no emissions from the onboard source of power (for example, hydrogen fuel cell vehicles and EVs). Electric vehicles are broken further into two categories: BEVs and PHEVs.

1. Executive Summary

In this document, the California Public Utilities Commission's (CPUC) Energy Division Staff (Staff) presents *(1)* analysis and recommendations for actions to improve distribution planning and project execution for the electric Investor-Owned Utilities (IOUs) and *(2)* analysis and recommendations to improve the IOUs' Distribution Resource Planning data portals and their Integration Capacity Analysis (ICA) maps.

Related to **distribution planning and project execution**, this proposal addresses the challenge of adapting these processes to better plan for and accommodate the anticipated increase in load growth from Distributed Energy Resources (DER). These new loads, (e.g. a new EV fast charging depot), can be large in terms of the electric capacity required to energize them and the system needs to be ready to energize quickly. However, large loads are more likely to trigger long lead time capacity upgrades, which can mean long energization timelines for new load. For example, if a large Direct Current Fast Charging (DCFC) station requires a substation upgrade, it could take up to eight years before that site is energized even if the developer is ready to be energized in a few months. In the face of these potential long lead times for distribution system upgrades, proactive planning is required to energize new loads in a timely manner. However, it will be important to manage any potential ratepayer impacts of increased investments as a result of proactive planning and investments.

The anticipated increase in the pace and scale of electrification and the growth in economic development (e.g., cannabis, high tech campuses, data centers) will require utilities to improve their distribution planning process (DPP). The current paradigm of the distribution planning and execution process is reactive and conservative. Historically, electric utilities relied on customer applications (e.g., energization requests) to justify significant distribution system investments. This was sufficient because the energization requests were for projects that also took time to develop (e.g., housing development), allowing utilities ample time and ability to complete grid upgrades to meet customer needs. However, given the nature of EV loads, which can be of equivalent size to that of a skyscraper (e.g., 5 MW) yet be installed in a matter of weeks, this practice is no longer sufficient. The new paradigm of the distribution planning and execution process must become more proactive by anticipating new loads and being prepared to serve them without lengthy distribution upgrades. In short, a desired outcome of more proactive distribution planning and execution would be that fewer customer requests are waiting for long lead time distribution upgrades before they can be served. This proactive planning must be well-informed by ensuring that the utilities use forecasts and modelling tools to guide proactive investments.

This staff proposal addresses planning for capacity on the IOUs distribution system in a high distributed energy resource (DER) future, and execution of the related distribution capacity projects. The proposal aims to 1) analyze issues with current distribution planning and execution and, 2) make proposals to improve distribution planning and project execution to prepare for electrification and other load growth. The proposal also aims to understand the root causes of current issues leading to capacity shortfalls and energization delays, and prevent them from occurring in the future.

This staff proposal was in development when Governor Newsom signed into law two bills relating to energization delays, Senate Bill 410 (Becker, 2023) and Assembly Bill 50 (Wood, 2023). Several of the proposals here respond to requirements in those bills relating to distribution planning improvements. If the recommendations contained in this staff proposal are implemented, they should contribute to more timely energization for customers by ensuring utilities are planning in advance of large loads materializing on the distribution grid.

Past decisions and law have already granted the IOUs sufficient authority to implement many of the recommendations contained in this proposal.

In relation to distribution planning and project execution, CPUC Staff recommend the following:

- Commission to allow utilities to use bottom-up, known load data to determine load growth.
- Utilities to improve method for setting caps on load growth from Integrated Energy Policy Report (IEPR) data.
- Commission to provide flexibility on which IEPR vintage utilities can use in distribution planning and develop method for incorporating newer IEPR data into existing planning.
- Utilities to expand the DPP forecast horizon to align with the IEPR and expand the planning horizon to 10 years (Maintaining the horizon for project deferral at 5 years).
- Utilities to improve forecasting and disaggregation with scenario planning.
- Utilities to improve disaggregation methodology for load growth currently based on economic modelling.
- Utilities to create a 'pending loads' category in the DPP.
- Utilities to develop prioritization methods beyond the current consideration of project need dates.
- Utilities to consider distribution planning results when doing other distribution work (integrated planning).
- Utilities to develop bridging strategies (e.g. flexible service connection) to better accommodate energization requests that trigger distribution capacity work.
- Utilities to prepare a load flexibility DPP assessment.
- Commission to allow more flexible inputs for utilities to request distribution capacity costs in their General Rate Cases (GRC).
- Utilities to submit community engagement plans that address equity.
- Utilities to deprioritize DIDF to free up stakeholder time.
- Utilities to include metrics to evaluate equity in utility distribution plan reporting.
- Utilities to include metrics to track project execution in utility distribution plan reporting.
- Utilities to report up-to-date known load project tracking and to the CEC.
- Utilities to facilitate better coordination and data sharing between the DPP and transportation electrification planning.

Related to **data portals and ICA maps**, covered in Sections 4 and 5 below, this staff proposal aims to improve the usefulness of these tools for DER planning, siting and interconnection, and to improve the design or ease of use of these tools.

In relation to data portals and ICA maps, CPUC Staff recommend the following:

- Utilities to incorporate more detail of the limiting criteria into ICA results in the data portal access.
- PG&E and SDG&E to remove all registration requirements for data portal access.
- Utilities to utilize the 15/15 rule, not the 15/100/15 rule, for decisions about data redaction protecting individual customer privacy for the ICA, GNA, and DDOR.
- Utilities to modify ICA maps to enable straightforward customer creation of limited generation profiles (LGPs).
- Utilities to modify ICA methodology to make use of LGP application information.

- Utilities to create a new report that includes ICA results appended to the current rule 21 quarterly interconnection report which allows for a comparison between ICA values and the quarterly interconnection timelines report.
- Utilities to develop new reporting aimed at understanding the frequency of potentially erroneous zero load ICA values.
- Utilities to incorporate load ICA results into internal IOU energization business processes and publish metrics.
- Other miscellaneous ICA usability and data portal improvements, included in appendix A.

2. The Current Distribution Planning and Execution Process – Background and Recent History

The Distribution Planning and Execution Process (DPEP) is a core electric utility work area. Per Public Utilities (PU) Code Section 218, the IOUs are responsible for owning, controlling, operating, and managing the distribution system. The development of the Distribution Investment Deferral Framework (DIDF) provided some of the first explicit Commission regulation of aspects of that process. In 2018, Decision (D.) 18-02-004 established requirements for each utility to identify system needs and deficiencies based on the California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) load forecast and develop projects to meet those grid needs. The annually required Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR) filings provide narrative descriptions and analytical data from the IOUs on the identified grid needs and proposed projects to meet those needs. This process provided transparency to the Commission and stakeholders, allowing better insight into several distribution planning issues we are seeing today including capacity constraints and energization delays, but may have also hindered the flexibility of distribution planning to adapt to changes in load growth.

Put simply, the Distribution Planning Process (DPP) uses forecasts of future electricity demand to identify grid needs, and plan solutions to upgrade the grid. For each solution, an Execution Process that comes after the DPP involves creating the workplan and schedule, detailed project planning, design, and estimating, permitting, and construction. Creating the workplan and schedule may include prioritizing projects so they can be completed before customers' respective need dates (i.e., the date on which expected load growth will create a violation[1] on the grid). Generally, projects that have the nearest need dates are completed first, and projects that have need dates that are years in the future may be left in the planning stage to be reviewed again in later distribution planning cycles if there will be sufficient time to complete them. This process has historically been at the utility's discretion and is necessarily fluid as forecasts may change, and customer needs may be delayed, accelerated, or cancelled.

The Execution Process covers the final phases in the process flow, focusing on the detailed planning and construction of new infrastructure or upgrades (See Figure 2-1). The success of the IOUs in this phase is influenced by various factors beyond distribution planning and can be subject to delays due to related tasks such as land acquisition and environmental permitting. Construction timelines depend on various factors, including permitting, land acquisition, and resource coordination. The time required to clear these dependencies is influenced by customer readiness, project size, complexity, geography, and community impact. When construction activities are complete, and a project is operational, final information on the project completion and new infrastructure details are inputted into utility databases.

2.1. The Current Distribution Planning and Execution Processes

Each utility currently conducts a DPP where they forecast future load on the distribution system, including both demand and generation, and determine when and where upgrades will be needed. The current DPP can be broadly broken down into the following steps:

1. Historical Load Profile Review

[1] See Section 2.1.4 for a description of violations of capacity, voltage, and reliability.

2. Forecast Adoption
3. Load and DER Disaggregation
4. Grid Need Identification
5. Solution Development

After the DPP, the Execution Process determines how the solutions are designed, prioritized, and constructed. This process can be broadly broken down into the following steps:

1. Project Prioritization in Workplan
2. Project Scoping
3. Planning, Designing, and Estimating
4. Permitting, Sourcing, and Release
5. Construction

The steps listed above generally characterize the main activities undertaken by the three IOUs and are not intended to perfectly capture each utility's process nor prescribe how an ideal process would work. These steps may also occur concurrently, or even be skipped under some circumstances. In the sections below, we describe each step in more detail. This Staff Proposal suggests improvements to both the DPP and the Execution Process, which are sometimes referred to together as the DPEP.

Figure 2-1: *Steps of the Distribution Planning and Execution Process Timeline*
Time in Months, Forecast Adopted Before Process Begins, Historical Load Profile Review is Concurrent with Grid Load and DER Disaggregation.

	Grid Load and DER Disaggre-gation	Grid Need and Solution Identification	Project Prioriti-zation*	Project Scoping*	Plan, Design and Estimating	Permitting, Sourcing and Release	Construction	Close**	Total for Project Execution
SCE Circuit	5	4		4 - 6	4 - 7	4 - 11	3 - 4	2 - 4	**20 - 36**
SCE Substation	5	4		8 - 9	6 - 9	4 - 40	11 - 18	3 - 6	**36 - 88**
PG&E	5	4	1 - 12	2 - 10	2 - 14	4 - 24	4 - 24		**14 - 96**

Note: SDG&E did not provide estimates for most of their execution process, only noting that timelines are variable, and so SDG&E is not included here.
* Some projects identified because of a short-notice customer application may avoid the normal Distribution Planning Process and jump directly to these steps.
** SCE noted a final step after construction where the work is transmitted to mapping and accounting organizations to be logged.

Source: IOU Responses to Assigned Commissioner's Amended Scoping Memo and Ruling in R.21-06-027.

2.1.1. DPP Step 1: Forecast Adoption

As a first step of distribution planning, the utilities choose the IEPR forecast scenarios which will be the basis of the next year's load growth forecast. The IEPR is published annually in Quarter 1. The utilities jointly propose IEPR scenarios in May and request CPUC Energy Division approval. The utilities then hold a workshop for the Distribution Forecasting Working Group (DFWG) within 2 weeks to present the chosen scenario and provide justification. There is a public comment period following the workshop for stakeholders to provide input on the proposed scenarios. Energy Division must approve the proposed IEPR scenarios by August 1st.

This is the process followed if the utilities propose to use an official IEPR scenario. However, if the utilities, upon reviewing the published IEPR demand and DER scenarios, determine that alternate datasets are necessary due to deficiencies in available IEPR datasets, they may file an Advice Letter to propose alternate datasets. The scenarios proposed through the Advice Letter will go through the same process for approval described above to approve the IEPR scenario, including a workshop and public comment. If contested or deemed by ED as non-compliant ED may direct the utility to resolve outstanding issues.

2.1.2. DPP Step 2: Historical Load Profile Review

A new DPP cycle begins in earnest in early fall after the annual peak loads of the summer have passed. Typically, the peak load period is from June to September, so the DPP begins in October. Every circuit peak demand is analyzed by distribution engineers to determine if any unusual conditions, such as load transfers, generator losses, and weather were impacting the peak. If determined so, these data points are removed or altered to give a view of the grid at peak demand during normal conditions. These historical figures are then normalized to correspond to a 1 in 10 weather year. This becomes the starting point for the forecast.

2.1.3. DPP Step 3: Load and DER Disaggregation

The IEPR is a statewide forecast. It provides energy use down to specific geographic regions or "planning areas" of the state. However, to plan the distribution system with the granularity necessary to reflect distribution capacity issues, the utilities must disaggregate the forecast further to the substation bank, the circuit, and the circuit segment. CEC forecasting currently produces some granular data during the generation of its forecasts and as inputs to CAISO transmission planning, but that is not directly created for or used within distribution planning. Load and DER disaggregation methodologies are discussed at the DFWG workshop described in 2.1.1. The methods of disaggregation are reported at length in the Grid Needs Assessment, filed annually in R.21-06-017 by the utilities on August 15th.

The utilities start with known loads, data derived from real applications for service that customers have made for a discrete amount of capacity at a specific premise, vetted by utility staff. Utilities engage with customers interested in energizing new loads, and broader community engagement can contribute to earlier submission of these applications. These known loads appear in large quantities in the first year of the forecast but drop off significantly in future years.

The way known loads are related to the IEPR differs by utility and has changed over time. In past distribution planning cycles, PG&E and SDG&E subtract the known loads from the load growth forecasted over 10 years in the IEPR and disaggregate the remainder through economic modelling, often to later years of the forecast. SCE instead had subtracted each year's known loads from the yearly IEPR load growth but argues that the IEPR does not capture all the types of load growth that they are seeing and designates some known loads as incremental to the IEPR amounts. For example, in their 2023 GNA, SCE reported that commercial electric vehicle chargers, indoor cannabis cultivation, and temporary power were categories of load not accounted for by the IEPR forecast and known loads of these types are thus not subtracted from the total forecasted IEPR load growth.[2] All the utilities can also make

[2] 2023 Grid Needs Assessment of Southern California Edison Company, Section 3.2.1 Load Disaggregation at 13, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M517/K610/517610166.PDFocx (ca.gov)

changes to their disaggregation processes during each planning cycle. For example, SCE is switching to a 10-year comparison in the current cycle.[3]

Utilities also have different methods for the "economic" disaggregation of load outside of known load data. PG&E and SDG&E accomplish this by splitting the load growth by customer class (residential, commercial, industrial) and then allocating it to circuits using geospatial analysis. They use the software LoadSEER to model substation and feeder demand forecasts by incorporating economic variables, weather data, satellite imagery, and data analytics to assign each circuit in the service territory a likelihood of increasing load by customer class. SCE considers similar factors when creating a time-series econometric model that produces monthly and hourly load forecasts for each circuit. Each circuit is assigned an allocation factor based on annual energy growth from both known loads and the econometric model. Based on the probabilities or allocation factors calculated through this economic modelling, any remaining load growth from the IEPR forecasts (after known loads are subtracted) is distributed to the circuits across the system.

For both methods, the output is then reviewed by distribution engineers and adjusted as deemed necessary.

A similar type of disaggregation is completed for different categories of DERs, including energy efficiency, transportation electrification, customer sited solar and battery storage, and fuel substitution. The IEPR accounts for these BTM resources which are allocated to the circuits in a utility's service territory based on methodologies specific to each DER type. Utilities may use adoption models in some cases, similar to the methodology used in the *Electrification Impact Study Part 1*[4], to assign DERs to circuits with characteristics that the utility determines to be a likely adopter. Additionally, SCE has conducted a Transportation Electrification Grid Readiness (TEGR) study, a new type of bottom-up analysis, and included it in its 2025 GRC filing to map large fleet operators to circuits for select locations. Based on Staff's communication with SCE, SCE has indicated they may use TEGR-like methods in future DPP cycles. Detailed disaggregation methodologies for each DER type are described annually in utility GNA filings.

2.1.4. DPP Step 4: Grid Need Identification

Utilities use power engineering software to model the operation of their distribution systems based on the forecasted net load (load growth + DER growth). Peak loads from the forecast are modeled and violations of capacity, voltage, and reliability are determined using power flow analysis for line sections. Simpler algebraic methods are used to determine capacity violations at the circuit and bank level. A capacity violation occurs when the forecasted 1 in 10 peak demand on a circuit or line section is above the capacity for which the conductor is rated or the utility determined limit. A voltage violation occurs when Rule 2 voltage limits (±5%) are exceeded at a primary node on a distribution feeder. A reliability violation occurs when a capacity violation appears due to a forced or planned outage situation modeled under peak conditions where the customers impacted must be temporarily served by other assets for 24 hours or more.

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[3] 2023 Independent Professional Engineer Distribution Planning Advisory Group Reports. PG&E, SCE, SDG&E.
[4] Electrification Impacts Study Part 1, May 2023, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K423/508423247.PDF

The forecasted grid needs are reported annually in the GNA. The report describes the type of grid need, the affected infrastructure, the year each grid need first occurs, and the extent of the need.

2.1.5. DPP Step 5: Solution Development

Utility distribution engineers review the needs identified in the GNA and determine the optimal solution to address the needs individually, or multiple needs together when feasible. The assessment of the grid needs includes consideration of circuit characteristics, phase imbalance, timing and duration of need, circuit topology, circuit tie availability, nearby circuits with available capacity, reactive power flow, and the ease of building new infrastructure. The upgrade selected is the one that is least cost, best fit, and just-in-time to mitigate the violation.[5]

The first solutions considered are low-cost solutions that utilize existing grid assets. These include load transfers to nearby circuits with available capacity and phase balancing by moving load between the three phase conductors. If the need cannot be met with existing grid assets, new equipment must be installed. An example of a traditional "wires" solution is to add a new conductor or upgrade an existing conductor to increase capacity or to enable back tie load switching to alleviate the overload. The utilities also assess the opportunity to solve the grid need with a DER solution, either utility-owned or through a third party contract.

The chosen planned investments are reported annually in the DDOR. Each identified solution is evaluated for its feasibility to be met with a DER by considering the cost effectiveness, market assessment, and certainty of the need. More information on project screening and prioritization for deferral can be found in the utility DDORs.

2.1.6. Execution Step 1: Project Prioritization

After grid needs are identified and solutions are developed, some projects move forward to scoping and full execution. Currently, projects are largely prioritized by need date, with the aim of completing all distribution capacity projects shortly in advance of the related grid need. This means that some projects would be immediately moved to scoping while others would be deprioritized if the time to execute the project is much less than the time until the modelled grid need occurs. SCE[6] and SDG&E[7] both note that they aim to complete all projects in advance of the grid needs, and if needed will redirect funding to distribution capacity work to meet this goal. PG&E[8] says it does not currently have the funding to cover all its required distribution capacity projects, and thus must prioritize funding between different types of projects. In general, utilities with any constraint on project execution, whether from funding, supply chain issues, or workforce constraints, may have to prioritize between projects and choose some to delay past their need dates.

2.1.7. Execution Step 2: Project Scoping

This step in the execution process starts from the high-level solution identified in DPP Step 5 and conducts desktop analysis to create the detailed project scope, including what equipment must be installed, modified, removed, or replaced. The scope is socialized across various relevant utility departments dependent on the needs, possibly including Design and Estimating, Land, Environmental,

[5] 2023 Distribution Deferral Opportunity Report of San Diego Gas & Electric at 6
[6] Responses to Amended Scoping Memo Appendix A by Southern California Edison, Appendix A at [Page 7]
[7] Responses to Amended Scoping Memo Appendix A by San Diego Gass and Electric, Appendix A at [Page 2]
[8] Responses to Amended Scoping Memo Appendix A by Pacific Gas and Electric Company, Appendix A at [Page 2]

Civil Design, Civil Construction, Construction, and, where applicable, Substation Design, Transmission Planning, Transmission Protection, and Substation Construction.[9]

2.1.8. Execution Step 3: Planning, Design, and Estimation

The project schedule is created including the project activities, durations, and sequences. An estimator visits the project site to identify the work necessary at the location. Detailed designs are produced, including a circuit map change sheet, overhead or underground construction drawings, a detailed cost estimate including material, labor, and construction costs, and supporting load calculations.[10]

2.1.9. Execution Step 4: Permitting, Sourcing, and Release

Projects may be required to secure permits, easements, and environmental reviews. Permits may be required based on local government agencies, such as ADA compliance or Caltrans review for projects near highways. Environmental review can include screening for environmental risks and review by biologists, cultural resource specialists, environmental field specialists, and land planners.[11] Extended permitting timelines and evolving requirements can impact distribution capacity projects, leading to engineering re-work and timeline delays[12].

Materials are sourced through a dual strategy, with commonly used items preordered to address potential shortages proactively, while specialized equipment undergoes a competitive bidding process. The project manager then ensures all necessary documentation, budget alignment, and proper authorization are in place before construction commences, assuring a seamless and efficient project construction.[13]

2.1.10. Execution Step 5: Construction

Projects are actually constructed in this final step of the execution process. The construction timeline is dynamic, influenced by project scope, complexity, material availability, weather conditions, and terrain characteristics[14]. Initiation of construction primarily relies on the IOU successfully navigating dependencies, including permits, land acquisition, and resource coordination. Delays and challenges in this phase are primarily attributed to external factors including emergency response creating workforce or material issues, weather slowing construction, or environmental conditions like discovering the need for soil remediation.

2.2. How We Got Here: Historic Load Growth, Conservative Planning Process, and PG&E Behind on Projects

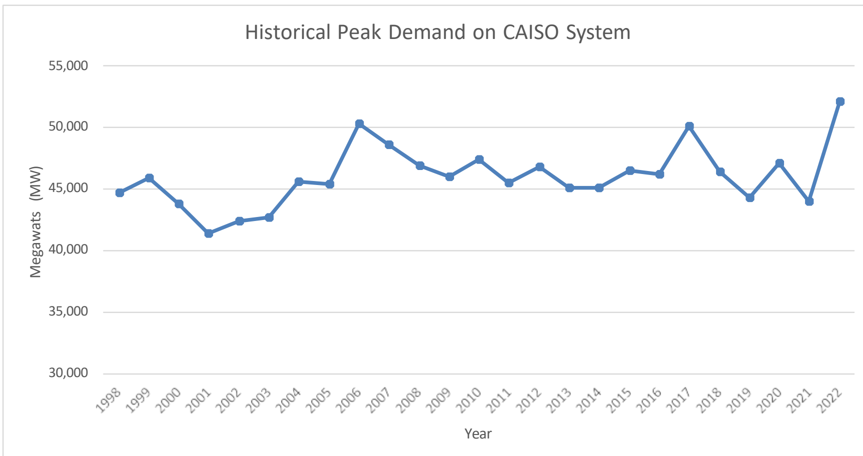
2.2.1. California is Experiencing a Historic Change in Load Growth, with Transportation Electrification Playing a Key Part

California is exiting a prolonged period of relatively stable and consistent demand for electricity. Thanks in part to energy efficiency efforts and rooftop solar, the last 25 years have seen a relatively flat trend in

[9] Responses to Amended Scoping Memo Appendix A by Pacific Gas and Electric Company, Appendix A at 2
[10] Responses to Amended Scoping Memo Appendix A by Pacific Gas and Electric Company, Appendix A at 2
[11]Responses to Amended Scoping Memo by Pacific Gas and Electric Company, Page 17
[12] Responses to Amended Scoping Memo by Southern California Edison, Page 11
[13] Responses to Amended Scoping Memo Appendix A by Pacific Gas and Electric Company, Appendix A Page 3
[14] Responses to Amended Scoping Memo Appendix A by Pacific Gas and Electric Company, Appendix A Page 4

electricity usage across the state. Figure 2-2 below shows that peak historical demand across the CAISO system has been remarkably consistent (with 2022 standing out as the highest peak demand ever recorded). Within this historical context, the current distribution infrastructure was generally sufficient to meet demand, although distribution upgrades have been needed sporadically to meet the needs of new or relocating development.

Figure 2-2: Historical Demand on the CAISO System has Remained Consistent over the Past 25 Years

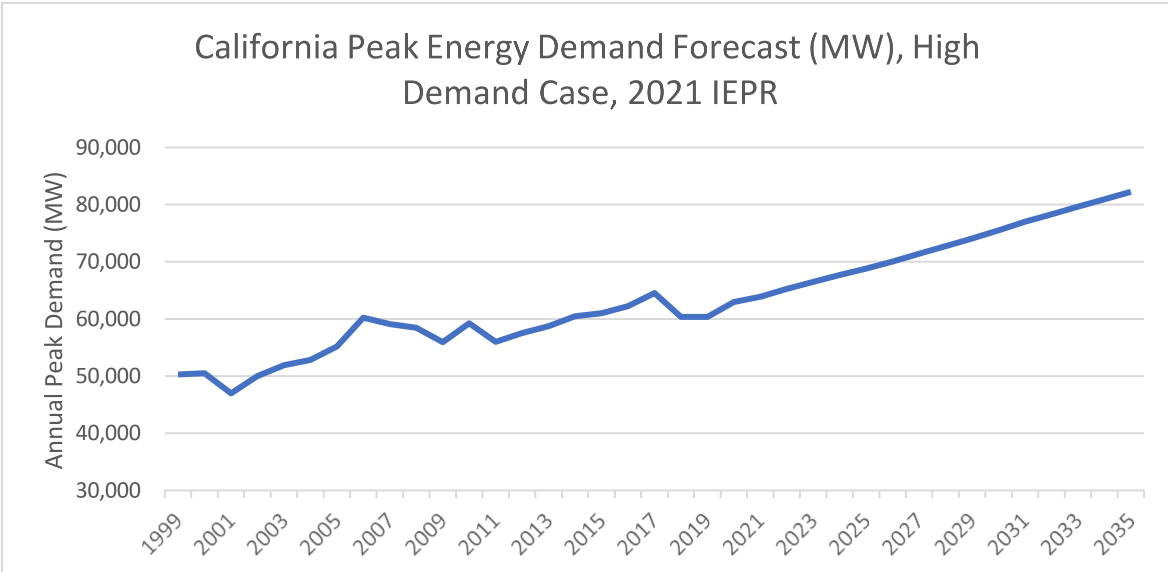


Source: CAISO Peak Load History, https://www.caiso.com/documents/californiaisopeakloadhistory.pdf

Both transportation and building electrification have altered this historical paradigm. Due to ambitious state climate policies and the increasing need to mitigate climate change, California has begun to see a significant increase in electricity usage that is expected to continue over the coming decades. This increase is due primarily to electric vehicle adoption and building electrification. The growth of new energy-intense sectors like data centers and indoor cannabis cultivation, as well as the increased peak demand from a more variable climate due in part to indoor climate control, are also likely to contribute to this overall load growth. In its recent 20-Year Outlook, the CAISO planned for a peak system demand of about 65 GW in 2040, well above any of the historical figures shown above. This load growth hides an even larger growth in demand, up to a peak of 74 GW in 2040, though offset by forecasted growth of behind-the-meter resources, largely solar.[15] Data from the 2021 IEPR clearly shows this historical shift, with Figure 2-3 below showing a clear change around 2022. These data indicate a load increase of about 40 percent by 2040, compared to current levels.

[15] *See* http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf, Table 3.1-2. These figures are for the CAISO system only, not the full state demand. Note that the distribution system is generally designed to keep the power on even when behind-the-meter solar power is disrupted.

Figure 2-3: CEC Forecasts Show Historical Shift in Load Growth, Beginning Around 2022



Source: 2021 CEC IEPR Demand Forecast, https://efiling.energy.ca.gov/GetDocument.aspx?tn=241206

This emerging energy demand landscape is significantly different from recent history. While current distribution planning practices may have been effective in the past, there is no guarantee they will work to meet this new future. The rate of load growth and exact locations where that load will appear on the grid system remain uncertain, making distribution planning an increasingly challenging and difficult task.

New EV charging stations present a particular challenge because they can require large amounts of load on relatively short notice. Historically, significant loads were associated with large projects like malls and industrial facilities that took multiple years to construct. This allowed utilities enough time to construct the necessary distribution grid infrastructure before the electrical service was needed. Major upgrades to the distribution circuits can take up to three years to execute, and major upgrades to substations can take up to eight years. EV charging stations, by contrast, can request service equivalent to a new neighborhood or factory but can be installed in a matter of weeks. The utilities may not have enough advanced awareness of the service need to complete related distribution capacity projects, which has led to long energization timelines for some customers as those projects are completed. It is understandable that, in this situation where the utility does not know that a customer will be requesting energization on a specific line segment, they may be underprepared to quickly deliver service. While improvements to the distribution planning process aim to help utilities be more prepared for this situation, there will always be uncertainty. Therefore, customers, particularly customers that require large loads, have a greater responsibility to notify utilities in advance of their service need. However, even while following best practices customers may occasionally face, and may need to plan for, lengthy time periods to complete grid upgrades, some of which can take as long as 8 years.

In short, California is currently undergoing a historic shift in load growth in which overall demand will grow significantly and the types of load growth may look drastically different than they did in the past. Distribution planning will necessarily have to evolve in response to these changes.

2.2.2. The Historic Change in Load Growth Calls for a More Robust and Forward-Looking Distribution Planning and Execution Process

To accommodate the historic change in load growth described above, utilities must adapt their respective distribution planning processes to anticipate where and when these large loads (e.g., DCFC plaza, port electrification, etc.) may materialize. In other words, utilities must be proactive in their planning and execution of capacity investments in order to promote timely energization of loads that may materialize in the future. Today, as a result of accelerated load growth and existing capacity constraints for some utilities, namely PG&E, new energization requests have triggered reactive capacity work more often than in the past, potentially leading to long energization timelines. In these cases, utilities should attempt to accommodate these projects to the extent feasible, but customers should also work to engage the utilities as early as possible. The staff proposal discusses this in more detail in section 3.2.10. Increased load growth may also lead to additional major infrastructure projects with long lead times, such as substation projects that can take up to eight years. Additional distribution capacity projects identified through proactive capacity planning and energization requests could lead to workforce constraints, issues with sourcing materials, or other issues with project execution. To the extent utilities have robust distribution planning in the medium and long term, they can mitigate some of these execution issues. For example, SCE has noted that the number of substation projects needed in the next five to ten years may overwhelm its capacity to execute on those projects, but that it could mitigate potential workforce constraints by staggering these projects, completing some earlier than needed.[16] Generally, proactive planning should improve utilities ability to execute projects smoothly, for example by developing a larger workforce and or sourcing needed materials early. In order for these types of strategies to work, increasing the mid- and long-term reliability of the load growth forecast and disaggregation should be key goals for distribution planning.

The current distribution planning process relies heavily on known loads, or customer requests for energization, to confirm where additional distribution capacity is needed. Outside of this near-term, reliable data, current utility processes do not seem to identify needed distribution upgrades with enough confidence to clearly justify their costs. If these current methods remain unchanged in a period of historic load growth, many needed distribution projects may not be identified with sufficient time to execute the projects, leading to long energization timelines for customers. To the extent distribution planning can become more robust, particularly in the mid- and long-term, these energization timelines can be reduced. However, some long energization timelines may still occur when large new loads apply for rapid energization with minimal lead time. Distribution planning and execution should become more robust and forward-looking, aiming to plan for load growth further into the future and proactively plan for transportation and building electrification where cost-effective, understanding that it is also the responsibility of customers seeking to energize large new loads to work with the utility well in advance of their needs.

[16] SCE's Comments To The Administrative Law Judges' Ruling Seeking Additional Information From Investor-Owned Utilities On Their Distribution Planning Process at A-11

2.2.3. Current Utility Processes and Regulatory Requirements May Hinder the Move to Robust and Forward-Looking Distribution Planning, Contributing to Long Energization Timelines

Current Distribution Planning practices are limited in how they can adjust to the new landscape of load growth. Some requirements implemented by the Commission, as well as the utilities' own standard planning processes, may hinder how the utilities develop their mid- and long-term distribution planning, contributing to potential energization delays or long lead times.

CPUC Decision (D.) 18-02-004 required that the CEC's IEPR serve as a primary input into IOU distribution planning. The IEPR provides an annual statewide energy forecast to be used for electric grid planning that is currently integrated into planning processes for the electric transmission system and energy resource development. D.18-02-004 required that utilities propose, seek comments on, and incorporate a selected IEPR scenario into distribution planning to determine the amount of expected load growth. However, using a planning scenario intended for the whole grid system to inform planning and load growth for each individual distribution circuit has proven difficult. Estimates of total load growth from the IEPR have consistently fallen below the actual energization requests received by the utilities, as discussed in more detail below. In summary, many utilities incorporated the IEPR data in ways that underestimated growth in the mid- and long-term, which presents a particular challenge in a time of historic load growth.

D.18-02-004 also required that the results from the utilities' distribution planning serve as a primary input to their requests for funding in their GRCs. The IEPR data used in distribution planning becomes increasingly out of date by the time it is used in GRCs, and in recent GRCs this data has not fully reflected the historic shift in load growth described above. In addition, to the extent that distribution planning underestimates the need for projects in the mid- and long-term, it may also underestimate the needed funding within the GRC. These two factors present a risk of underfunding for distribution capacity work within the GRC process. Currently, only PG&E has noted that they lack adequate funding to cover needed projects. In its current GRC, SCE has included the supplementary TEGR analysis outside of traditional distribution planning to justify a higher request for distribution capital.

Finally, utilities lack reliable ways to disaggregate load growth without known load data. In distribution planning, the location where a load shows up determines whether and where a distribution capacity upgrade is needed. General estimates of total load growth are not very useful without reliable estimates of exactly where that load growth will appear, down to the circuit, and even, premise level. However, outside of known load data that comes from customer energization requests, utilities tend to use general economic and demographic modeling to spread expected load growth across their systems, with particular methods to estimate load from DERs. More robust mid- and long-term disaggregation of load growth, using statistical methods and information outside of direct energization requests, should be a key goal for distribution planning.

2.2.4. PG&E has Fallen Behind on Distribution Capacity Work, Due in Part to Prioritizing Wildfire Hardening and Repairs, Contributing to Delays

In its filings within this proceeding, PG&E noted that it currently considers half of its identified distribution capacity projects to be unfunded, totaling 277 projects expected to cost about $1 billion. PG&E asserts that funding constraints are contributing to project delays and ultimately energization delays for customers. SCE and SDG&E are not currently experiencing this issue. PG&E fell behind on distribution capacity work in 2018 and 2019, when it directed significant funds from other work areas to wildfire mitigation. In 2018 and 2019, 45 percent and 35 percent of PG&E distribution capacity funding was reprioritized toward wildfire mitigation-related efforts, leading to 199 project delays.[17] This reduction in spending on distribution capacity coincided with some of the historic trends in load growth described above, with PG&E's territory seeing early adoption of EVs and load growth from new data centers and the cannabis industry. PG&E already faced a backlog of distribution capacity work exactly when increases in load growth began to drive the need for additional distribution capacity projects. Although PG&E spent funds above its approved GRC amounts in 2020, 2021 and 2022, it has not been able to catch up on needed distribution capacity work. These overlapping problems have led to continued delays in distribution capacity projects and related delays in customer energization.

In Phase 2 of its current GRC, PG&E has requested additional ratepayer funding to make up this deficit and accommodate increasing load growth, in accordance with procedures laid out in PUC Section 937. As described above, PG&E faces additional problems beyond the historic shift in load growth facing all the other IOUs, which has led to its request for additional funding. It is not clear whether the other IOUs will make a similar request.

2.2.5. Recent Delays and Extended Timelines for Customer Energization and Related Legislation

A historic increase in load growth, including large transportation electrification loads applying for energization on an accelerated timeline compared to historic energization requests, has set the underlying conditions for an increase in customer energization delays and long lead times for energization. This may be exacerbated by issues with distribution planning and execution that hinder robust planning in the mid- and long-term. Finally, PG&E's particular situation and its need for additional funding led to additional energization delays and long lead times throughout its territory.

Within this context, two new pieces of legislation related to customer energization were signed into law by Governor Newsom in 2023. Both bills defined energization using the same language, and identified distribution planning as one aspect of customer energization:

> "'Energization' and 'energize' mean connecting customers to the electrical distribution grid and *establishing adequate electrical distribution capacity or upgrading electrical distribution or transmission capacity* to provide electrical service for a new customer, or to provide upgraded electrical service to an existing customer. *The determination of adequate electrical distribution*

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[17] Responses To Amended Scoping Memo Appendix A By Pacific Gas And Electric Company at 11-13.

capacity includes consideration of future load. 'Energization' and 'energize' do not include activities related to connecting electrical supply resources."[18] (Emphasis added)

Senate Bill (SB) 410 (Becker, 2023) noted many reports of new housing developments and other individual customers facing energization delays and long-lead times. Assembly Bill (AB) 50 (Wood, 2023) similarly aims to address delays in connecting customers to the grid and ensuring adequate coordination with local governments impacted by these delays.

Both bills also included sections relating to utilities distribution planning. SB 410 required that utilities consider a variety of factors in distribution planning, including (a) decarbonization goals and plans, (b) electrification policies for buildings and the transportation sector, (c) state and local government plans, (d) known loads, load projections provided by the CEC, and (e) projections of load that exceed CEC forecasts. SB 410 also makes explicit that utilities should upgrade the distribution system to meet state and local decarbonization goals and should comply with utilities' obligation to serve by conducting sufficient advanced planning to timely energize customers.

AB 50 required that (1) each utility evaluate and update its existing distribution planning processes to improve the accuracy of projected demand and ensure timely energization, and (2) each utility must have annual meetings with interested stakeholders to discuss issues related to distribution planning.

This Staff Proposal on Distribution Planning Improvement was conceived of before these bills were introduced. The current proposal includes elements that meet all of the statutory requirements in SB 410 and AB 50 related to distribution planning, as detailed in the sections below and in Table 8.

3. Issues with Current Distribution Planning and Project Execution and Related Proposals

Table 1: Summary of Issues, Goals and Proposal in Section 3

Issue with DPEP	Issue Description	Related Key Goals	Related Proposals
Planning Process	**3.1.1** Planning Process: IEPR Data as an Input into Distribution Planning.	**Key Goal 1: Use the newest available data in distribution planning.**	3.2.3 Provide Flexibility on which IEPR Vintage Utilities Can Use in Distribution Planning and Develop Methodology for Incorporating Newer IEPR into Existing Planning
	3.1.2 Planning Process: Reconciling System-Wide IEPR Load Forecasting and Bottom-Up	**Key Goal 1: Improve the method for creating load growth caps from IEPR forecasts.**	3.2.2 Utilities to Improve Method for Setting Caps on Load Growth from IEPR Data
			3.3.6 Up-To-Date Utility Known Load Project Tracking and Reporting with the CEC.

[18] PU Code Sections 931(b) and 933.5(g), added by Senate Bill 410 (Becker, 2023) and Assembly Bill 50 (Wood, 2023) respectively.

	Circuit-Level Forecasting	**Key Goal 2: Allow flexibility for utilities to bring in reliable bottom-up data when available.**	3.2.1 Allow Utilities to use Bottom-Up, Known Load Data to Determine Load Growth
	3.1.3 Planning Process: Mid- and Long-Term Loads Disaggregation	**Key Goal 1: Improve Mid-Term (2-4 Years) Load Disaggregation.**	3.2.7 Utilities to Create a 'Pending Loads' Category in DPP
		Key Goal 2: Improve Long-Term (5-15 Years) Load Disaggregation.	3.2.5 Utilities to Improve Forecasting and Disaggregation with Scenario Planning
			3.2.6 Utilities to Improve Disaggregation Methodology for Load Growth Currently Based on Economic Modelling
Coordination and Planning	**3.1.4** Coordination and Planning: Medium- and Long-Term Planning and Coordination Challenges	**Key Goal 1: Use long term forecasting to proactively plan for electrification.**	3.2.4 Utilities to Expand the DPP Forecast Horizon to Align with the IEPR and Expand the Planning Horizon to 10 Years (Maintaining the Horizon for Project Deferral at 5 Years)
			3.2.5 Utilities to Improve Forecasting and Disaggregation with Scenario Planning
			3.2.6 Utilities to Improve Disaggregation Methodology for Load Growth Currently Based on Economic Modelling
		Key Goal 2: Integrate the DPP with other distribution level work.	3.2.9 Utilities to Consider Distribution Planning Results When Doing Other Distribution Work (Integrated Planning)
			Proposals 3.2.4, 3.2.5, and 3.2.6 also related.
TE Growth	**3.1.5** TE Growth: Reliable Anticipation of Transportation Electrification Loads that Apply for Energization on Short Notice	**Key Goal 1: Bringing TE loads into distribution planning early and accurately, to the extent feasible.**	3.2.7 Utilities to Create a 'Pending Loads' Category in DPP
Delays and Long Energization Timelines	**3.1.6** Delays and Long Energization Timelines: The Impact of	**Key Goal 1: IOUs to develop strategies, such as temporary DER placement or**	3.2.10 Utilities to Develop Bridging Strategies to Better Accommodate Energization Requests that Trigger Distribution Capacity Work

	Distribution Capacity Upgrades on Customers	**limits on energy use as bridging solutions for energization requests that require distribution capacity projects.**	
		Key Goal 2: Improved tracking of distribution capacity project execution and related funding.	3.3.5 Include Metrics to Track Project Execution in Utility Distribution Plan Reporting
Cost Recovery	**3.1.7** Cost Recovery: Load Growth Acceleration and Cost Recovery Challenges	**Key Goal 1: Utilities can meet funding needs for distribution capacity work, currently covered by the framework described in SB 410.**	No Proposals, this is covered by the cost recovery mechanism in Senate Bill 410, as described above.
		Key Goal 2: Provide More Flexibility for Utilities to Request Distribution Capacity Costs in the GRC.	3.2.12 Recommend More Flexible Inputs for Utilities to Request Distribution Capacity Costs in the GRC
Grid Modernization	**3.1.8** Grid Modernization: Effective Utilization of DERs and Load Flexibility	**Key Goal 1: Prepare Utility Distribution Planning and Project Execution for Grid Modernization.**	3.2.11 Utilities to Prepare a Load Flexibility DPP Assessment
Community Engagement	**3.1.9** Community Engagement: Coordination and Engagement with Local and Tribal governments, Planning Agencies, ESJ Communities, and Local Developers	**Key Goal 1: Effective IOU coordination with local planning entities.**	3.2.13 Utilities to Submit Community Engagement Plans that Specifically Address Equity
Equity	**3.1.10** Equity: Equity Considerations in	**Key Goal 1: Proactively consider equity as a priority**	3.2.8 Utilities to Develop Prioritization Methods Beyond the Current Consideration of Project Need Dates

	Distribution Planning	**in distribution planning.**	3.2.13 Utilities to Submit Community Engagement Plans that Specifically Address Equity
			3.3.4 Include Metrics to Evaluate Equity in Utility Distribution Plan Reporting
Project Prioritization	**3.1** Project Prioritization: Improving Project Prioritization when the Prioritization is Useful or Necessary	**Key Goal 1: Improve prioritization under constrained funding.** **Key Goal 2: Incorporating equity considerations into prioritization.** **Key Goal 3: Prioritizing the acceleration of future projects.**	3.2.8 Utilities to Develop Prioritization Methods Beyond the Current Consideration of Project Need Dates

3.1. Issues with the Current Distribution Planning & Execution Processes (DPEP)

In this section, Staff presents various issues with current distribution planning and execution processes, and related key goals for improvement. This section aims to ground and provide evidence for the proposals in Section 3.2 and 3.3, provide a common framework for discussion and comments, and to inform Commission work on distribution planning and execution going forward.

3.1.1. Planning Process: IEPR Data as an Input into Distribution Planning.

Description: The annual DPP uses an IEPR forecast as a key input. However, by the time it produces results in the DPP via GNA and DDOR reports the information is based on data that is two years old. Specifically, the IEPR released in any given year is based, in part, on the summer peak of the year before, and the DPP that will use that IEPR will be released the following year. By the time the DPP is released, the IEPR vintage used will be 1 year behind, and the data used to develop that IEPR will be based on information (e.g., summer peak) from 2 years prior to the release of the DPP. Utilities request use of specific IEPR forecast scenarios, which are first approved by the Commission, then used for analysis of future grid needs in the annual Grid Needs Assessment. These results from distribution planning are then used as an input into the following GRC. For example, as shown in Table 2, SCE's Test Year 2025 GRC (filed in 2023) was based on the 2022 DPP results which used the 2020 IEPR (filed in 2021). It is unclear to what extent newer IEPR data could be used within distribution planning, as the data needs to be available in time for the power flow analysis that informs the IOUs GNAs, if not earlier. Newer IEPR data could be used in the GRC, as discussed in sections 3.1.7 and 3.2.12 below. As shown in

Figure 3-1, the IOU use of IEPR data generally starts in Quarter 3 each year and it takes 6-8 months for the IOUs to implement the forecast and generate grid needs for the following year. However, the IOUs should aim to use newer data within distribution planning if reasonably available, instead of data that is significantly out of date, which will then inform their GRC cost estimates.

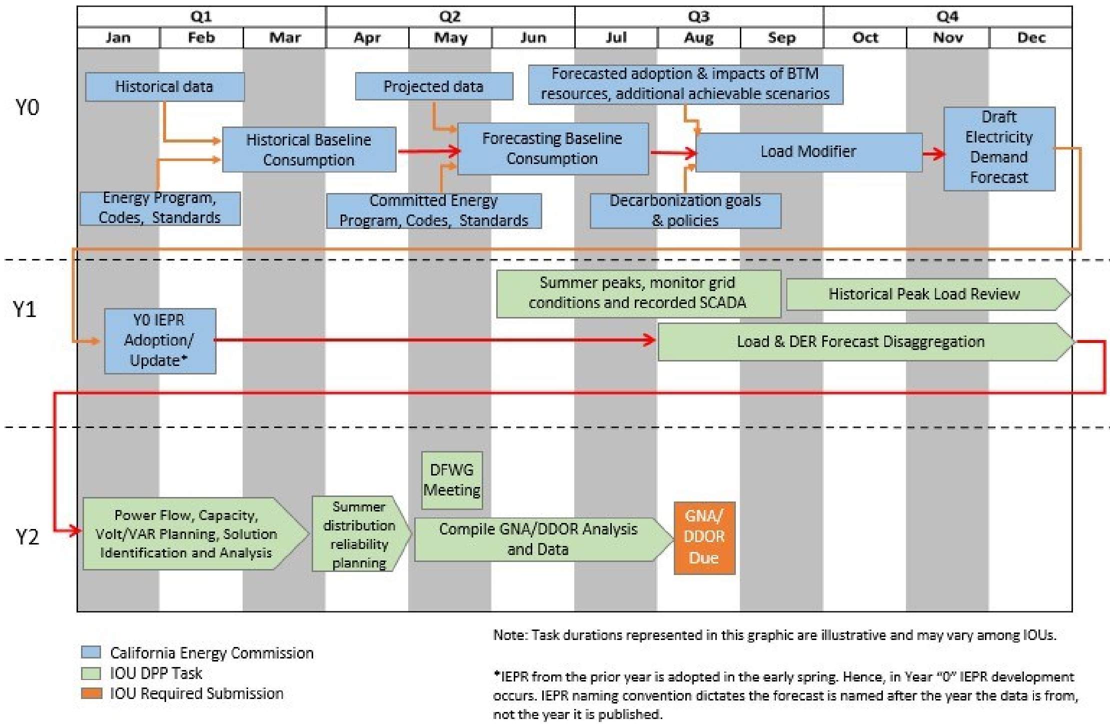
*Table 2: Linking IEPR Vintages to DIDF and GRC Filings**

IEPR Vintage	IEPR Release Date[19]	Distribution Planning Cycle	Associated GNA/DDOR	GNA/DDOR Release Date[20]	Associated GRC	GRC Release Date[21]
2018 IEPR	2/20/2019	2019-2020	2020	8/15/2020		
2019 IEPR	2/20/2020	2020-2021	2021	8/15/2021	PG&E 2023 SDG&E 2024	6/30/2021 5/16/2022
2020 IEPR	3/23/2021	2021-2022	2022	8/15/2022	SCE 2025	5/12/2023
2021 IEPR	2/17/2022	2022-2023	2023	8/15/2023		
2022 IEPR	2/10/2023	2023-2024	2024	8/15/2024	PG&E 2027	Q2 2025
2023 IEPR	1/30/2024	2024-2025	2025	8/15/2025	SDG&E 2028	Q2 2028

**Red font indicates future filings*

[19] Integrated Energy Policy Report - IEPR | California Energy Commission
[20] Annual Public Filings from Proceedings R.14-08-013 and R.21-06-017
[21] GRC Filings Available at CPUC General Rate Case Website

Figure 3-1: IEPR and Distribution Planning Process Workflow Chart



Source: Created by Energy Division Based on 2023 IEPR Narrative and the 2023 DIDF Schedule

Responsibility: Regulatory Issue

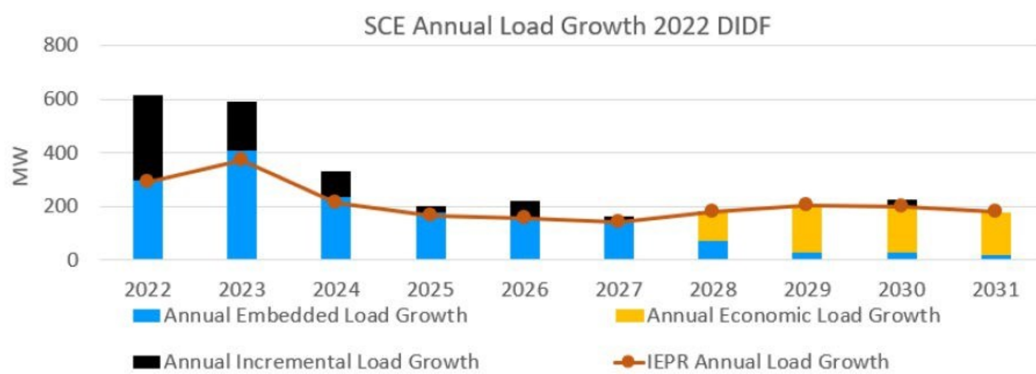
Key Goal 1: Use the newest available data in distribution planning. Where feasible, the DPP should use the newest available IEPR data and should incorporate newer data when it becomes available. To the extent this is not feasible, it may be reasonable for the IOUs to bring in other data sources because the IEPR data may not fully reflect recent developments in the economy, state policy, local needs, or other areas, as further discussed in sections 3.1.2 and 3.1.7 below.

3.1.2. Planning Process: Reconciling System-Wide IEPR Load Forecasting and Bottom-Up Circuit-Level Forecasting

Description: The current DPP uses IEPR forecasts to produce a cap for load growth for each year (SCE historical practice) or for the overall 10-year forecast period (SDG&E, PG&E and SCE current). This load growth cap has not historically aligned with the existing energization requests, A.K.A. "known loads," that utilities use to make projections for near-term load growth at the circuit level. The forecasting methods used by the utilities accommodate this misalignment in different ways. In the context of this proceeding and discussions with Staff, all IOUs have made changes to their methods for the current Distribution Planning cycle.

Historically, SCE both (1) categorizes many of its "known load" projects as incremental to the IEPR forecast, putting them outside the cap on load growth, and (2) moves some near-term known loads to later years of its forecast, using what it calls the “whirlpool method,” which is based upon the certainty SCE has in the various known loads and could lead to energization delays by pushing projects deemed uncertain into later years.[22] This can be seen in the graph below, where the incremental load is shown above the IEPR forecast (in black), and embedded load growth (the remainder of known loads) predominates for the first six forecast years, even though the significant majority of those embedded known loads actually fall into the first three forecast years.

Figure 3-2: SCE Load Growth Forecast for 2022-23 DIDF



Source: Independent Professional Engineer 2022 SCE DPAG Report

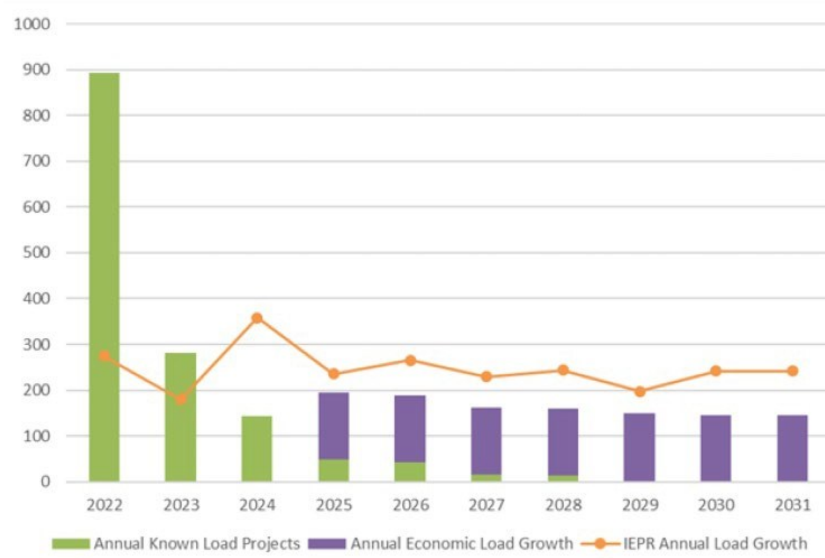
In the current DIDF cycle, SCE has modified its method to be more like the methods used by SDG&E and PG&E, described below.

PG&E and SDG&E use a different method. Rather than apply a load growth cap to each year, both utilities apply a load growth cap to the overall 10-year forecast period and reduce forecasted load growth in outer years to accommodate near-term known loads.

PG&E subtracts known load projects from the total growth cap, and then distributes the remaining load growth to later forecast years. In the 2022 DIDF cycle, as seen in Figure 3-3 below, this led to a forecast below the IEPR amount for every year after the second year.

[22] For a deeper description of the SCE Whirlpool Method, see the *Independent Professional Engineer 2022 SCE DPAG Report*, pages 14-18.

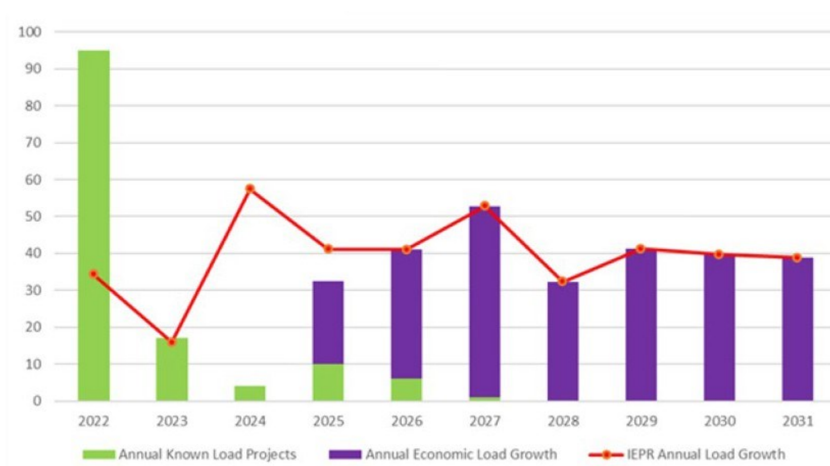
Figure 3-3: PG&E Load Growth Forecast for 2022-23 DIDF



Source: Independent Professional Engineer 2023 Post DPAG Report

Historically, SDG&E only began adding in additional load growth beyond known loads when the cumulative annual caps based on the IEPR reach the cumulative load growth from known loads. As seen in Figure 3-4 below, this leads to forecasts that correspond to the IEPR in later years, but distorts the forecast in years 3 and 4. In the current cycle, SDG&E has instead chosen to balance known loads by reducing load growth in the latest years of the forecast, improving the results in the mid-term.

Figure 3-4: SDG&E Load Growth Forecast for 2022-23 DIDF



Source: Independent Professional Engineer 2023 Post DPAG Report

The IEPR currently serves as "the basis for transmission and resource planning" for the larger electric grid.[23] Using the IEPR at the distribution level ensures that distribution planning broadly aligns with transmission and resource planning at the system-level, and for that reason the IOUs should continue to use the IEPR as one basis for their load growth forecasts. However, some of the current methods distort the IEPR forecasts in order to accommodate bottom-up known load information. (Or in SCE's case, the reverse is more true, where SCE pushes some bottom up known load information to later years to match the IEPR forecast). One issue with current distribution planning and execution is that ***the reconciliation between reliable bottom-up data and the IEPR load forecasts leads to distortions in how these same data sources are used.*** These distortions can lead to projects being delayed or long-lead time projects being identified late, in either case contributing to long energization timelines. To the extent feasible, the IOUs should use both the IEPR and known load data in ways that do not lead to these distortions. This means both working to lessen the discrepancy between the IEPR data and known load data (**Key Goal 1**) and, where that discrepancy remains, allowing the use of reliable, near-term known load data without distorting the use of the IEPR forecast (**Key Goal 2**). If the utilities conduct distribution planning in a way that underestimates load growth, this can lead to long energization timelines.

There are multiple possible reasons for the discrepancy between known load data and the IEPR load forecasts. As a starting point, this analysis presumes that both the IEPR forecasts and the known load data are relatively accurate, and that the most significant factor is *how this data is brought into distribution planning*, not the quality of either the IEPR forecasts or known load applications.

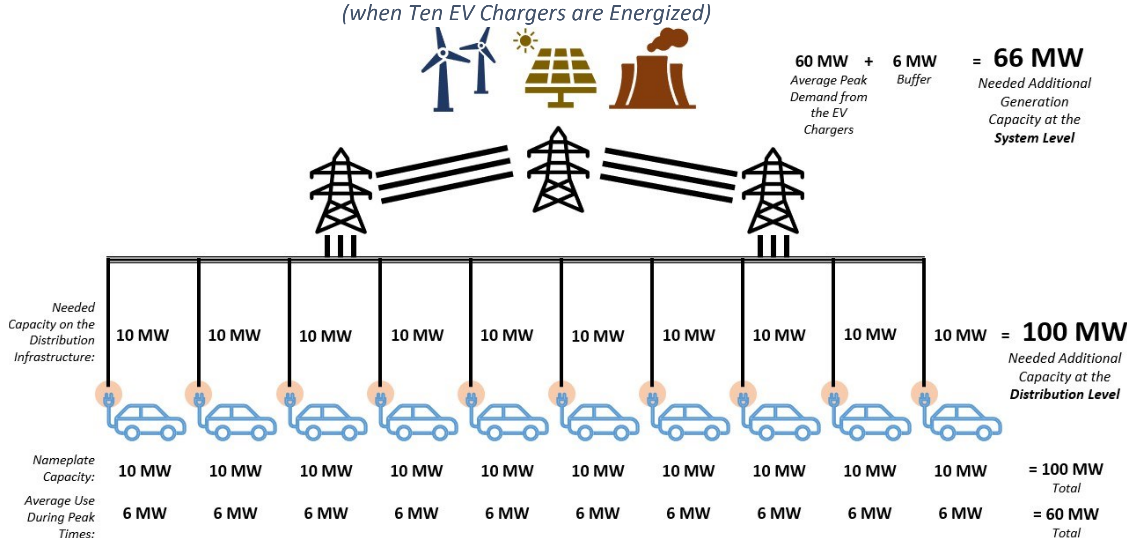
In part, this discrepancy emerges because the IEPR is a system-level forecast aimed at transmission and resource planning, which correctly presumes that the peak loads at each individual circuit will not occur simultaneously. The total capacity needed to reliably power the grid (also called the coincident peak) will always be lower than the sum of peak loads across each individual circuit (also called the non-coincident peak). While transmission and resource planning at the system-level should use coincident peaks, distribution planning at the circuit-level *should* plan for each individual circuit's peak load, or the non-coincident peak. Based upon this real difference between the system-level and the circuit-level, capacity needs between these two levels are not easily comparable.

For example, if ten 10 MW EV charging stations are energized across the state, each of the related circuits needs to have the capacity to accommodate the charging sites' incremental load at peak in addition to the peak of the other loads on that circuit. However, at the system-level, the state would build *less than* 100 MW of new generation capacity because the probability that all 10 charging stations are used at their maximum nameplate, at the same time as when the rest of the grid is also peaking, is low. In other words, applying system-level growth estimates based on system level coincident peak from the IEPR to circuit-level growth, without

[23] Memorandum of Understanding Between CPUC, CEC and the California Independent System Operator (CAISO) Regarding Transmission and Resource Planning and Implementation, December 2022. https://www.energy.ca.gov/sites/default/files/2023-01/MOU_Dec_2022_CPUC_CEC_ISO_signed_ada.pdf

taking this difference into account, can underestimate needs. For a visual representation of this example, see Figure 3-5 below.

Figure 3-5: Example of the Difference Between System Level and Distribution Level Need (when Ten EV Chargers are Energized)



To complicate matters further, the widespread adoption of EVs challenges the prevailing paradigm of loads being stationary. Although most EV chargers are stationary, EVs are mobile and will charge at different locations throughout the state as needed. For instance, an EV fleet vehicle may charge overnight at its home base, then throughout the day utilize public charging stations to extend its range and level of production. Loads like these will require electric capacity at various locations rather than simply allocated to one circuit as in the case of a stationary load. As EV adoption grows, the discrepancy identified between system-level and circuit-level capacity needs may increase.

Utility data from past distribution planning cycles show that the adjusted IEPR forecast for peak load in an IOU service territory is consistently below the sum of circuit level peak loads (9-12% below for SDG&E, and 16-21% below for PG&E, with SCE using an alternative method, see Table 3 below). Although capacity figures cannot easily be compared, energy figures (MWhs rather than MWs, a stock rather than a rate) should correspond between the circuit-level and system-level.

Table 3: Comparison of Peak System-Level Load from IEPR Forecasts with the Sum of Circuit-Level Peak Loads, PG&E and SDG&E (in GW)

Distribution Planning Cycle	2020-21 DIDF Cycle		2021-22 DIDF Cycle		2022-23 DIDF Cycle		2023-24 DIDF Cycle	
Utility	PG&E	SDG&E	PG&E	SDG&E	PG&E	SDG&E	PG&E	SDG&E
IEPR-Based Load Forecast	18.6	4.5	18.7	4.4	18.3	4.5	19.1	4.8
Load Forecast from Sum of Historical Peak Loading at the Circuit-Level	21.7	5.0	22.3	4.9	22.2	4.9	23.2	5.2
Circuit-Level as percentage of IEPR-Based	116%	112%	119%	110%	121%	109%	121%	109%

Source: IOU data from PG&E and SDG&E, SCE uses a different method based on the IEPR energy forecast so is not included here.

The discrepancy between known loads and the IEPR forecasts may also result from other factors. For instance, some load growth is not fully considered in IEPR (i.e. SCE's incremental loads), the IEPR data used in distribution planning is two years out of date, and some known loads will not ultimately appear on the grid. The exact reasons for this discrepancy are not currently understood. However, both theoretical reasoning and empirical evidence point to capacity needs being different between the system-level and the circuit-level. The system-wide IEPR does not perfectly reflect circuit-level capacity needs. Given this finding, it would be incorrect to insist on using the exact same load forecasts at these two levels. Both system-level and circuit-level forecasts can look to the IEPR as a basis while understanding that the current IEPR capacity forecasts are only strictly applicable at the system-level.

Responsibility: Regulatory Issue, IOU Issue

Key Goal 1: Improve the method for creating load growth caps from IEPR forecasts. The IOUs create the load growth caps for distribution planning from the year-over year growth in the IEPR forecast adjusted to count only distribution loads in their territories. However, as noted above, the way the IOUs apply IEPR-based capacity forecasts to distribution planning can underestimate actual circuit peak loading across the system, and similarly underestimate these year-over-year growth caps. This underestimation would inhibit distribution forecasting and planning. In the long term, it seems reasonable for utilities to move toward using the IEPR *energy* forecasts as the basis for their modelling, disaggregating new energy needs to the circuit level and then modelling the capacity needs of each circuit based on this added energy and appropriate load curves. Currently, SCE follows a method roughly along these lines. In the near term, it may be reasonable to adjust how the IEPR is incorporated into the DPEP to account for the difference between circuit-level peaks and system-wide peaks, as seen in currently available data.

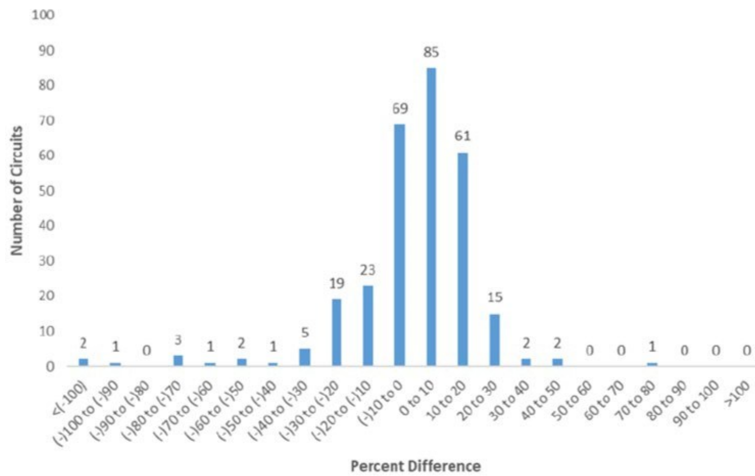
Key Goal 2: Allow flexibility for utilities to bring in reliable bottom-up data when available. Bottom-up known load data, and other similarly reliable near-term data on load growth, should be used to estimate load growth at the circuit level in utility distribution planning when available. Using this reliable, near-term data should not distort the use of IEPR forecasts in later years, as it currently does in all IOU processes. Similarly, utilities should not shift known load data to later years in order to adhere to the annual IEPR forecast capacity allowance, as SCE historically has done. Where available, reliable bottom-up data should be used as the basis for load forecasting, and the IEPR forecasts should be used directly, without distortion, when reliable bottom-up data is not available. In part, this flexibility acknowledges the real differences between the system-level and the circuit-level.

3.1.3. Planning Process: Mid- and Long-Term Load Disaggregation

Description: Disaggregation of forecasted new loads becomes less reliable in the mid- (2-4 years) and long-term (5-10 years). Estimates for the anticipated location (at the premise and circuit levels) of new loads on the electric grid are imprecise when they are not directly tied to existing energization requests, i.e. known loads. These known loads are generally reliable, but the data are only available in the short term, and by year three represent only a small part of the new load expected to eventually apply for energization. This is because customers typically do not plan out or communicate their needs to utilities three years or more in advance. In short, although planning[24] has been shown to be somewhat accurate one year out (see Figure 3-6 and Figure 3-7 below, showing relatively accurate predictions with slight over forecasts for PG&E), it becomes less reliable in later years. To the extent the planning horizon is extended from five to 10 years, it is uncertain that current disaggregation methods could produce reliable results for those years.

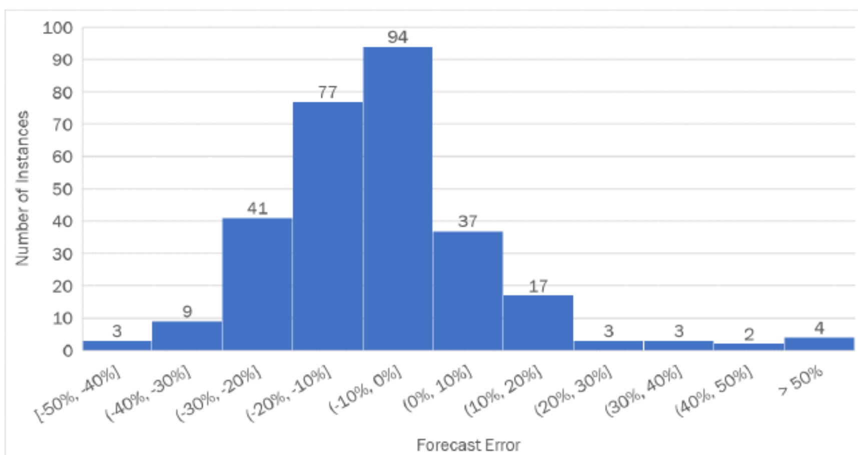
[24] Note the difference between forecast and disaggregation. Even with an accurate forecast for total load growth, disaggregating that growth to specific locations on the distribution system remains difficult without known load or similar data.

Figure 3-6: Percent Difference between Forecasted Year 1 Loads and Actual Loads for a Random Selection of Circuits, 2020-21 DIDF cycle, SCE (Positive Indicates Actual Loads Above Forecast)



Source: 2022 IPE SCE DPAG Report, Final, page 71

Figure 3-7: Percent Difference between Forecasted Year 1 Loads and Actual Loads for a Random Selection of Circuits, 2020-21 DIDF cycle, PG&E (Positive Indicates Actual Loads Above Forecast)



Source: 2022 IPE PG&E DPAG Report, Final, page 61

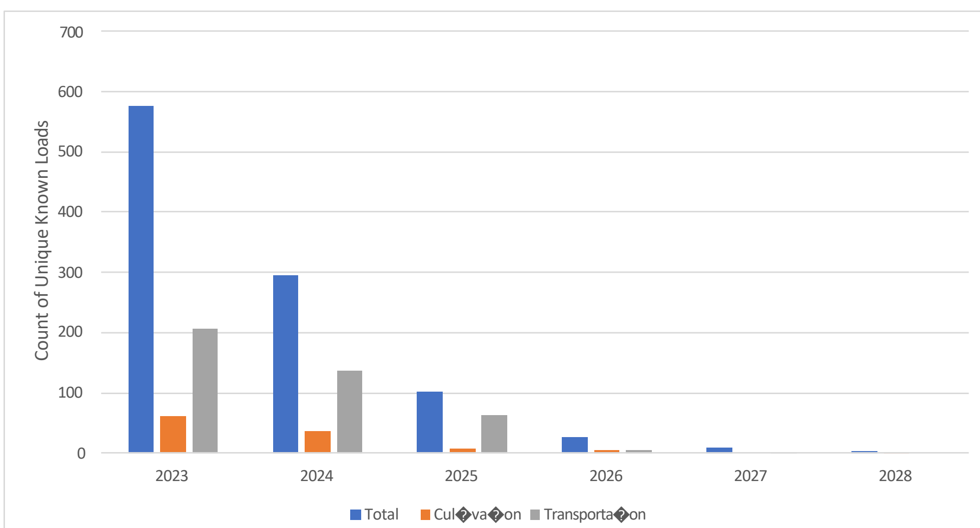
Mid-term (Years 2-4)

Data from the IOUs highlights the rapid drop in known loads after the first forecast year. We can see this same trend in Figure 3-2, Figure 3-3 and Figure 3-4 from section 3.1.1 above. In each of these figures, for each utility, it is clear that most known load data shows up in the near term and becomes increasingly absent in the mid-term. For PG&E, there is about 890 MW of load growth in year 1, about 280 MW in year 2, and about 150 in year 3. For SDG&E, there is about 95 MW of load growth in year 1, about 15 MW in year 2, and only 5 MW in year 3. SCE's "whirlpool method" doesn't easily allow for a similar comparison, but the same trend exists. In short, all the IOUs are using known load data to ground a substantial amount of their distribution planning, but this data exists only sparsely in the mid-term. To the extent this trend is common to the three IOUs, it likely reflects an *underestimation* of load growth in the mid-term, when customers have not yet submitted energization requests and thus known load data does not fully reflect expected load growth.

We note that PG&E's data likely shows a more extreme case because some of their backlog in distribution capacity projects is reflected in year 1 of the forecast, meaning year 1 includes load growth that has been carried over from previous years. This can be seen in Figure 3-7 above, where PG&E's year 1 forecast overestimates actual loads in part because previous distribution capacity projects were not completed and thus the associated loads could not be energized. Until they are energized, these associated loads would continue to count as known loads in the first year of future forecasts.

Data from SCE in Figure 3-8 below show similar results. These data are adjusted to account each unique project only once, even if there are multiple related customer applications or the customer seeks progressive energization over multiple years. In its 2023 dataset, although SCE was tracking almost 600 known loads in 2023, there are less than 300 in 2022 and about 100 in 2025. Again, this likely reflects an underestimation of load growth in the mid-term, when customers have not yet submitted energization requests and thus known load data does not fully reflect expected load growth.

Figure 3-8: Unique Known Load Projects in Each Year, Seen Decreasing Over Time



Source: 2023 Known Load Tracking Dataset, as analyzed by the IPE

At first glance, this may seem like an issue with forecasting, not with disaggregation. However, the main benefit of known load data is that it tells us ***where*** to expect new load, down to the exact premise. By comparison, forecasting the total amount of load growth based upon historical trends and/or the IEPR is relatively easy, but it becomes difficult to assign it to specific locations on the grid. In short, without reliable known load data pointing to the exact locations on the grid where load growth will appear, current methods only allow the IOUs to predict grid needs and plan related distribution capacity projects with limited confidence.

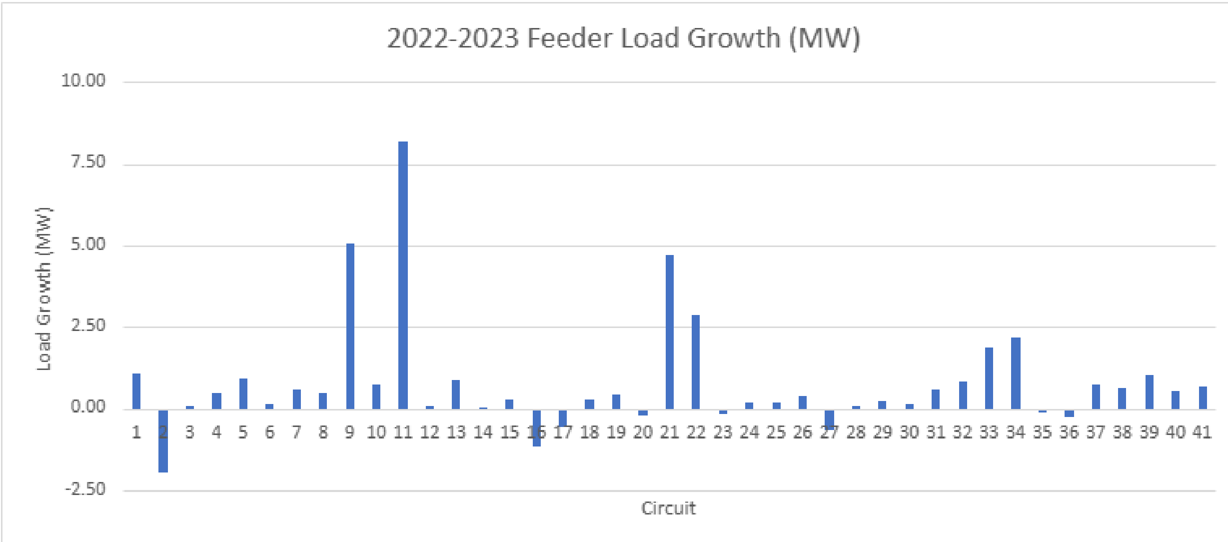
Long-term (Years 5-10)

Long-term distribution planning is significantly more challenging than near-term planning which responds primarily to known loads. Long-term planning has the task of using the IEPR's system level demand forecast, one large quantity for the entire service territory, breaking it down to the circuit level, and assigning these pieces of load to locations across the system; this process is known as disaggregation. Predicting the future is impossible, so utilities have developed methods to approximate this load growth over their system using reasonable assumptions described below, however, more advanced methods may be able to provide better results.

Current approaches to disaggregate forecasted load in later years to precise places on the grid remain speculative and unreliable. The utilities rely on various forms of economic modelling in the later years of their forecasts, which assigns forecasted load growth to specific locations based on economic, demographic, and other factors. In general, this leads to relatively even load growth across the grid, with somewhat higher growth in areas where the model shows significant electrification of heating/cooling or transportation. However, this economic modelling does not, and is not meant to, reliably predict the specific circuits where new loads will appear on the grid, especially for large new loads like new EV charging stations or new development. Instead, economic modelling predicts the likelihood of load growth, and then spreads forecasted load growth across its whole territory according to these predictions, which leads to relatively even load growth across circuits. These even load growth estimates tend not to reflect the possibility of large loads applying for energization at specific places.

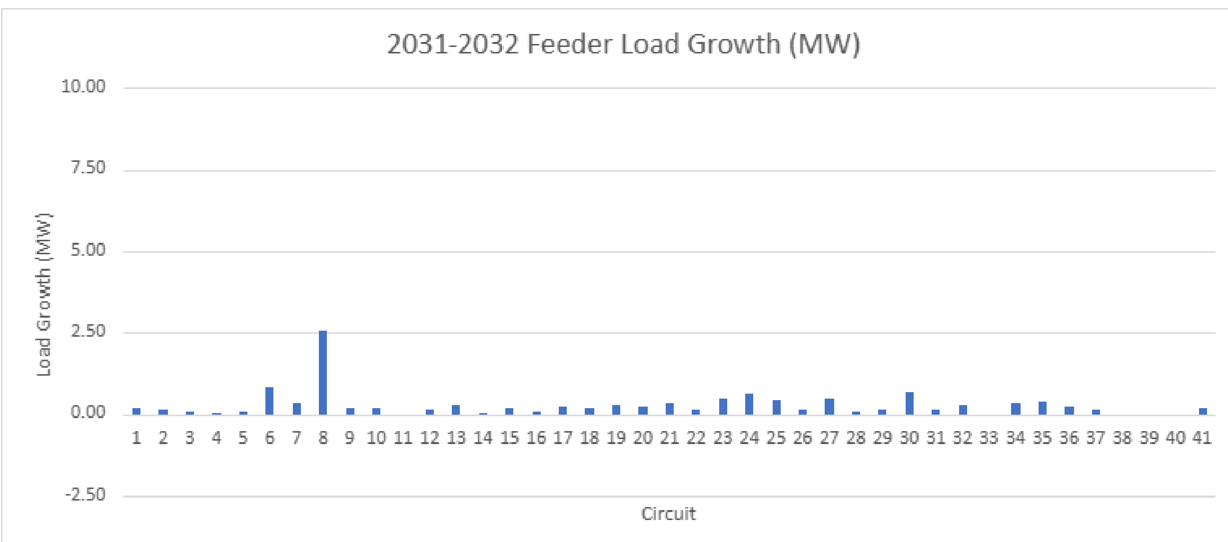
For example, consider the difference between forecasted load growth from PG&E in the near term as seen in Figure 3-9 below, largely based on known load data, to forecasted load growth in the long term as seen in Figure 3-10 below, based on economic modelling. The near-term data shows larger changes in load in specific locations, including decreases in load, with relatively small changes in most places. By contrast, the long-term data shows relatively even growth across the feeders, with no decreases in load. Because these are different forecasted years, we would not expect to see an exact alignment in the data—but we would expect to see the data follow a similar patter, that is look relatively similarly distributed as a whole. Instead, these graphs demonstrate how economic modelling does not predict the exact circuit or circuit segment where discrete new loads will appear on the grid.

Figure 3-9: Random Sample of PG&E Feeder Load Growth from the 2023 DIDF Cycle for 2022-2023



Source: IOU Data from PG&E

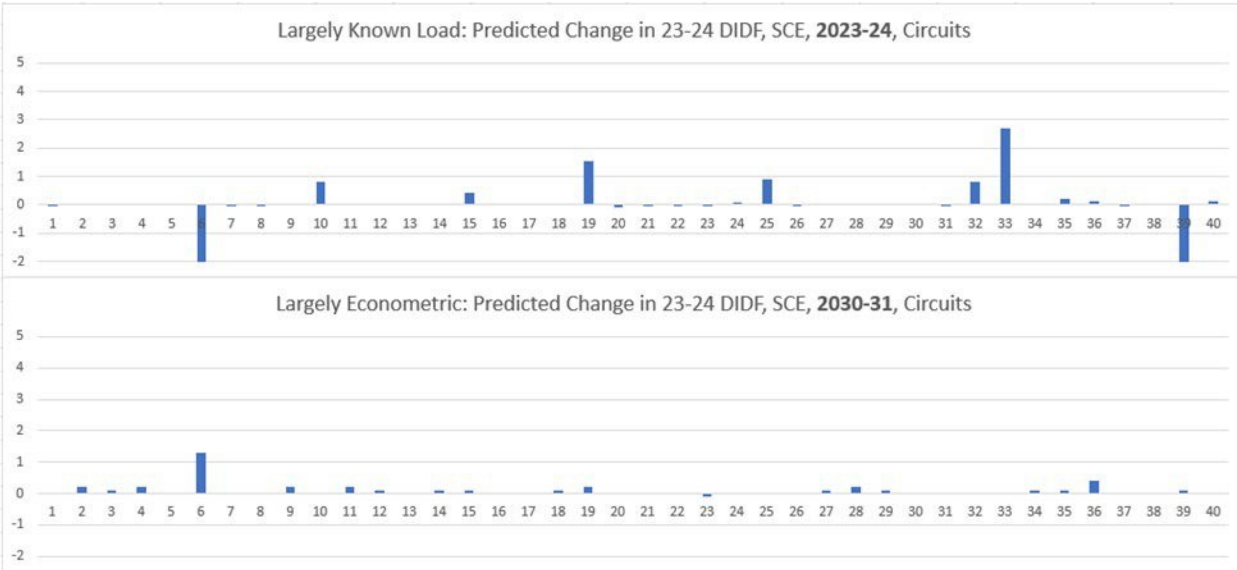
Figure 3-10: Random Sample of PG&E Feeder Load Growth from the 2023 DIDF Cycle for 2031-2032



Source: IOU Data from PG&E

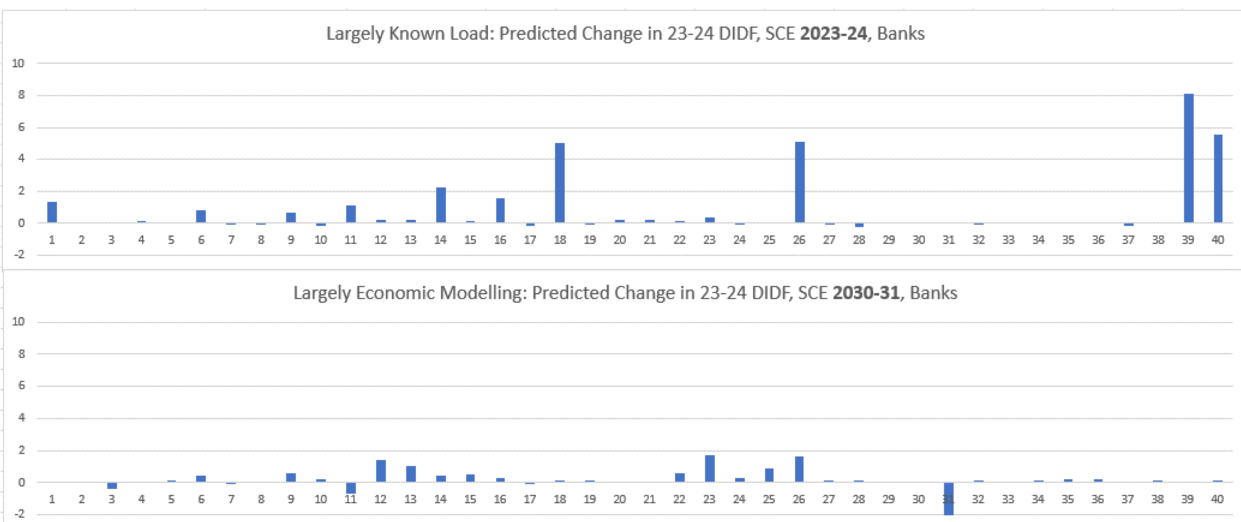
Data from SCE and SDG&E, assembled in Figure 3-11 to Figure 3-13 below, show similar results. In each case, random samples of 40 circuits (for SCE, substation banks also shown) generally show the difference between load growth based on known loads, which shows up in discrete locations on the grid, and load growth disaggregation based on economic modelling, which tends to be evenly distributed.

Figure 3-11: Random Sample of SCE Circuit Load Growth from the 2023 DIDF Cycle, Comparison Between Known Load-Based and Economic Model-Based



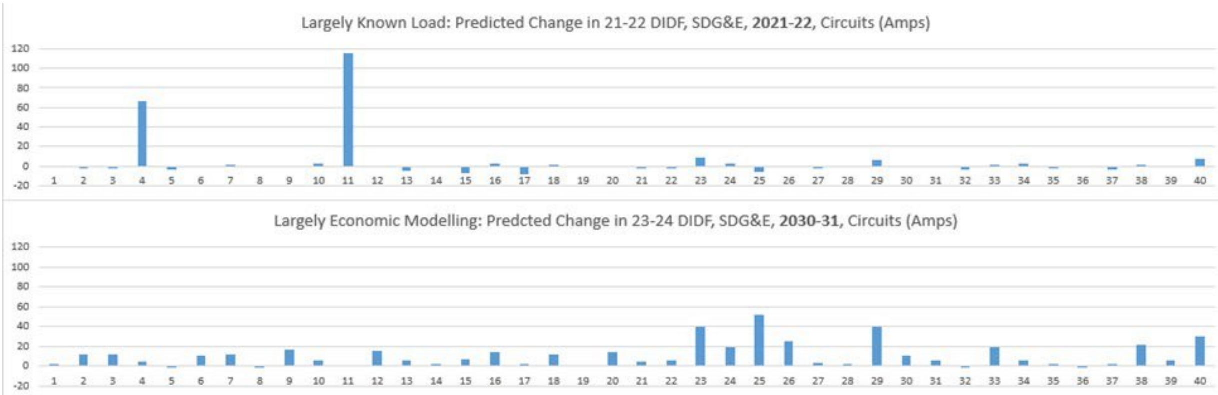
Source: IOU Data from SCE

Figure 3-12: Random Sample of SCE Substation Bank Load Growth from the 2023 DIDF Cycle, Comparison Between Known Load-Based and Economic Model-Based



Source: IOU Data from SCE

Figure 3-13: Random Sample of SDG&E Circuit Load Growth, Comparison Between Known Load-Based and Economic Model-Based



Source: IOU Data from SDG&E

In contrast to early forecast years, where known load data ties most load growth to specific circuits, econometric forecasts spread load growth much more evenly across circuits. Essentially, this is an issue with disaggregation: without a reliable means of disaggregating load to discrete locations on the grid corresponding to future energization requests, the IOUs choose to distribute IEPR-defined load growth relatively evenly across all circuits, based on an economic model. The economic model predicts to what extent every circuit will see load growth, and the IOU assigns load accordingly. On the circuit level, this strategy produces an estimate of load growth, but actual load growth will in most cases end up higher or lower, even significantly so. Although we can predict the probabilities of different amounts of load growth showing up at any circuit, when the IOUs turn those probabilities into specific estimates for load growth these estimates will by necessity have low precision, even if relatively accurate on average. In many cases, the actual amount of load growth that shows up will be significantly different than the estimate. Aggregated at higher levels, for example at the substation level, the current methods should become more reliable. Disaggregation in these later years inherently comes with uncertainty, as there is no way to know where future loads will show up. This uncertainty can be mitigated with more advanced methods.

Given that no reliable means exists to predict the exact location of energization requests in the long term, the current method of spreading out load growth relatively evenly is somewhat reasonable. However, statistical methods do exist to quantify this type of uncertainty, though they may require significant computing power. Rather than assign a specific amount of load to each location on the grid, which transforms a fundamentally uncertain quantity into a fixed amount, the IOUs could estimate the ***probability*** that a capacity limit is exceeded. For example, the IOUs could use Monte Carlo analysis, running thousands of random trials to estimate the probability that the thermal capacity limit on a line is exceeded. These probability figures better represent the real uncertainty about the need for future grid upgrades, potentially helping with long-term planning and integrating distribution capacity work with other workstreams. Importantly, using statistical methods to produce these probabilities may not work alongside power flow analysis, both of which can take significant computing power, so tradeoffs may exist between accurately modelling the physics of the grid system (through power flow analysis) and usefully modelling the real uncertainty in where future load growth may appear (through various statistical methods). Current forecasting of load on circuits and substation banks do not use power flow analysis, so these methods could be immediately applied. Power flow analysis is used for forecasting loading on circuit segments and modelling voltage issues.

In addition to enhanced economic disaggregation, other planning methods may be needed to create long-term certainty in planning. The Freight Infrastructure Plan (FIP) is designed to identify areas of high future EV charging demand to provide enough time for utilities to build out infrastructure to serve large loads. While these efforts are currently in development, utilities should be following the process and prepare to integrate it into the DPP when appropriate.

Responsibility: IOU Issue

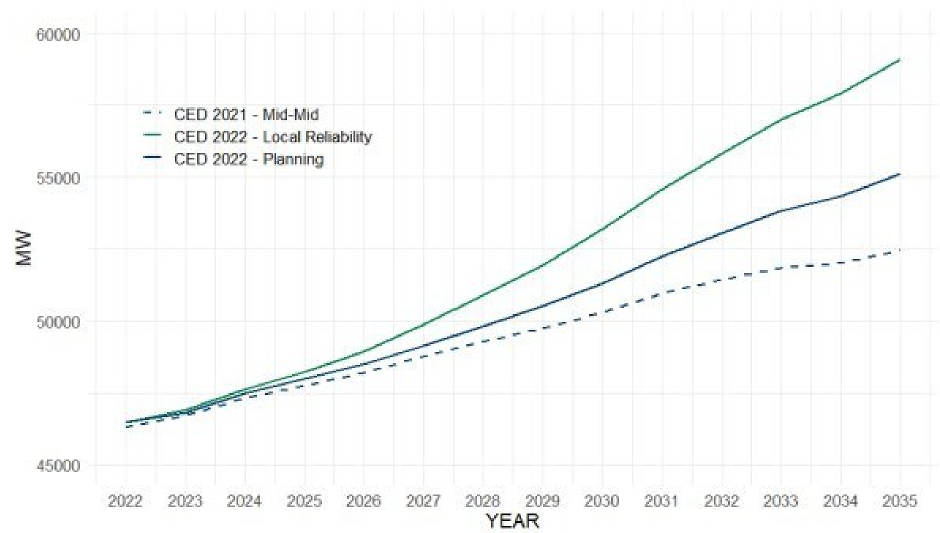
Key Goal 1: Improve Mid-Term (2-4 Years) Load Disaggregation. Distribution capacity projects at the circuit level typically take 1-3 years for project completion and may take longer under constrained resources or extenuating circumstances. To reliably upgrade circuits in advance of needs, the utilities should improve their methods for disaggregating mid-term load forecasts. This should focus on improving known load data through local government and community engagement and proactive outreach, and on developing additional bottom-up data on load growth that can be integrated into the DPP similarly to known loads. The outcome should be fewer customer requests requiring distribution capacity upgrades before they can be served.

Key Goal 2: Improve Long-Term (5-15 Years) Load Disaggregation. Projects to add or replace substation transformers or build new substations typically take 5-10 years for project completion and may take longer under constrained resources or extenuating circumstances. To reliably upgrade existing and build new substations in advance of needs, the utilities should improve their methods for disaggregating long-term load forecasts and prepare to incorporate long-term planning inputs from other sources e.g., the FIP. Improved longer-term forecasts would also facilitate integrated planning, which is when utilities combine distribution capacity upgrades with other distribution-level workstreams such as asset management and wildfire hardening (undergrounding), discussed in 3.1.4. This should focus on improving economic modelling and potentially bringing in statistical modeling techniques like Monte Carlo simulation which could estimate the probability of a capacity upgrade being needed. In addition, current economic disaggregation, which is based on historical data and other modelling, may reflect existing inequity in electrification and DER ownership. New methods or metrics may produce more equitable disaggregation of loads and ultimately more equitable distribution planning outcomes.

3.1.4. Coordination and Planning: Medium- and Long-Term Planning and Coordination Challenges

Description: The rate of electrification is increasing in response to state policy goals in transportation and building electrification. As shown in Figure 3-14 of the adopted 2022 IEPR, much of the load growth is expected to occur outside the current 5-year GNA planning horizon. SCE has expressed concerns that the magnitude of distribution upgrades needed in the period after the current 5-year planning horizon could be too large to meet at once.

Figure 3-14: Managed System Peak Demand Forecasts Used by the CAISO



Source: California Energy Commission 2022 IEPR, as provided in the CAISO TPP

However, loads are less certain the further out in time they are forecast, and there is a risk of overbuilding, building too soon to be fully utilized, or building in the wrong places. In part because of issues with disaggregation, there is lower confidence in the DPP forecast results for later years. Some projects that are included may not actually be needed, while many projects that are likely needed are not adequately forecasted. This creates difficulties with the planning and coordination of distribution capacity work in the medium and long term.

Distribution upgrades routinely take between 1-3 years for circuit projects and 5-10 years for substation projects to implement, requiring a robust mid- to long-term forecast to reliably meet needs in time. Utilities anticipate an increasing amount of long lead time substation level projects that have the potential to overwhelm their construction workforces.[25] Currently, IOUs have different planning horizons according to how long they anticipate different levels of grid upgrade to take. As shown in Table 3, distribution line work is expected to take between 1 and 3 years. Due to this relatively short upgrade time, PG&E and SDG&E report their planning horizon to be 3 years. However, substation level upgrades can take up to 10 years. SCE uses an explicit planning horizon of 10 years for substation upgrades while PG&E and SDG&E report using a longer planning horizon for substation upgrades as needed.

Table 4: *Timeline and Planning Horizon for each IOU Per Upgrade Type*[*]

[25] SCE Response to ALJ's Ruling Directing Responses to Questions on Track 1 Phase 1

* X indicates that timelines were not provided in utility responses.

	PG&E Upgrade Time	PG&E Planning Horizon	SCE Upgrade Time	SCE Planning Horizon	SDG&E Upgrade Time	SDG&E Planning Horizon
Distribution line work	1-3 years	3 years	1.5-2 years	5 years	1 year	3 years
Adding a new circuit from an existing substation	2-3 years	5 years	2-3 years	5 years	X	5 years
Add or replace substation transformer at an existing substation	3-4 years	5+ years	X	10 years	X	5+ years
Build a new substation	5-7 years	5+ years	7-10 years	10 years	X	5+ years

Source: IOU Responses to ALJ's Ruling Directing Responses to Questions on Track 1 Phase 1

As demand increases on the grid, the full context of grid upgrades should be considered together to ensure utility workforces are adequately prepared for the amount of work to complete.

Additionally, integrated planning between utilities distribution capacity work and other distribution work can be difficult or inadequate without reliable longer-term forecasts. Lack of coordination between distribution level workstreams can cause multiple projects on the same grid location or asset to occur at different times, duplicating work and increasing costs. Lack of coordination and a limited forecast horizon can also lead to the installation of grid assets with insufficient ratings compared to expected future load, leading to early replacement and increased costs. Especially as many utilities embark on significant distribution work related to wildfire risk, asset repair, and grid modernization, these new distribution projects should refer to a useful longer-term forecast of distribution capacity needs.

A useful long-term distribution forecast and plan likely requires comparing multiple scenarios or other statistical work that may not easily overlap with the complex power-flow simulations completed during current distribution forecasting and grid needs assessment. Utilities currently use full power-flow analysis to identify voltage deviations or other network issues, and to ensure the accuracy of loading forecasts in networked distribution systems, but do not use power flow analysis to model loading at the circuit or substation bank level. Full power-flow analysis, though a more accurate representation of the physics of the grid, requires significant computing power and time to complete. While this level of modelling remains necessary in the near-term, longer-term forecasts and grid needs assessments could focus only on capacity needs for circuits and substation banks and thus estimate loading based on assigning loads to specific assets (for example, every predicted new load would be assigned to a specific circuit and related substation bank).

Modelling loading on assets by summing all the related power needs, without detailed consideration of voltage or reactive power issues, would require orders of magnitude less time and effort than conducting a full power-flow analysis. This modelling is similar to the work Kevala or Cal Advocates conducted in their respective EIS and DGEM studies, which did not include power flow analyses but simply summed up power needs to the circuit and substation levels. As noted, utilities currently use a similar modeling technique on circuits and substation banks. Using this simplified modelling in later years would allow the development and comparison of multiple scenarios and the use of statistical methods like Monte Carlo analysis, which could ultimately lead to a more useful long-term forecast and grid needs assessment. Although this would not account for voltage deviations or reactive power issues, those types of grid needs can in general be resolved in the near term with capacitor banks, step-up transformers, or DERs.

Responsibility: Regulatory Issue, IOU Issue

Key Goal 1: Use long term forecasting to proactively plan for electrification. Expand the forecast horizon of the DPP to identify needs and projects further into the future. This will increase awareness of the quantity and quality of work needed to maintain an adequate distribution system and allow utilities to prepare better work plans and accelerate projects to smooth workload as needed. It will also provide the opportunity for long-term planning initiatives like the FIP to be integrated smoothly and appear in the distribution plan with context as opposed to being the lone projects in the 5-15 year timeframe. Accelerating projects will require additional prioritization inputs, which have the potential to proactively support the energy transition.

Key Goal 2: Integrate the DPP with other distribution level work. Distribution system upgrades should be coordinated with parallel workstreams such as wildfire hardening and asset management. Utilities are currently engaged in replacing and repairing aging assets, and in reducing wildfire risk from their systems. Both workstreams can involve the replacement of existing distribution infrastructure, which is then expected to last for decades. Increased awareness of future demand and loading conditions will provide valuable input to other distribution work to ensure the right equipment is installed, and upgrades are bundled with other work on the same grid location. Coordinated workplans will reduce costs and benefit all ratepayers.

3.1.5. TE Growth: Reliable Anticipation of Transportation Electrification Loads that Apply for Energization on Short Notice

Description: The California Air Resources Board (CARB) has mandated increased electrification for vehicles[26], freight[27, 28], and rail[29] transportation. The distribution grid should be able to

[26] See Advanced Clean Cars II: https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program/advanced-clean-cars-ii

[27] See Advanced Clean Fleets: https://ww2.arb.ca.gov/our-work/programs/advanced-clean-fleets

[28] See Advanced Clean Trucks: https://ww2.arb.ca.gov/our-work/programs/advanced-clean-trucks

[29] See Reducing Rail Emissions: https://ww2.arb.ca.gov/our-work/programs/reducing-rail-emissions-california

accommodate fleet charging to achieve decreases in GHG emissions and reductions in the trucking and freight pollution that often impacts disadvantaged communities. Traditionally, new large electric loads are associated with large construction projects that take years to be built. However, the EV charging depots needed to facilitate transportation and freight electrification, which can demand the power equivalent to a small town, can be installed by developers in a matter of weeks. This significant change in the typical timeline for the customer development of large load projects has left utilities with much less time to react to customer service requests, making the traditional timeline for energization too slow for this new type of project. These loads can be difficult for the utilities to precisely forecasts, which further exasperates the limitations to the utilities' distribution planning process as EV charger developers and fleet operators typically do not communicate to utilities about their projects until they are about to submit an application for new service. Without advance notice or accurate forecasting, these loads present a challenge to the current, largely reactive, planning process, and to grid planning in general.

To demonstrate the fact that EVSPs energization timeframes do not align with historic load requests, SCE has reported that, as of January 2023, there were zero EVSE projects requesting service in 2025. SCE expects the 2024 requests reflect less than 50% of what will be energized in that year and based on the current trajectory of EVSE load growth, expect at least 500 MW to be energized in 2025.

Table 5: *Snapshot of SCE's received EV charging load growth projects as of January 19, 2023*[30]

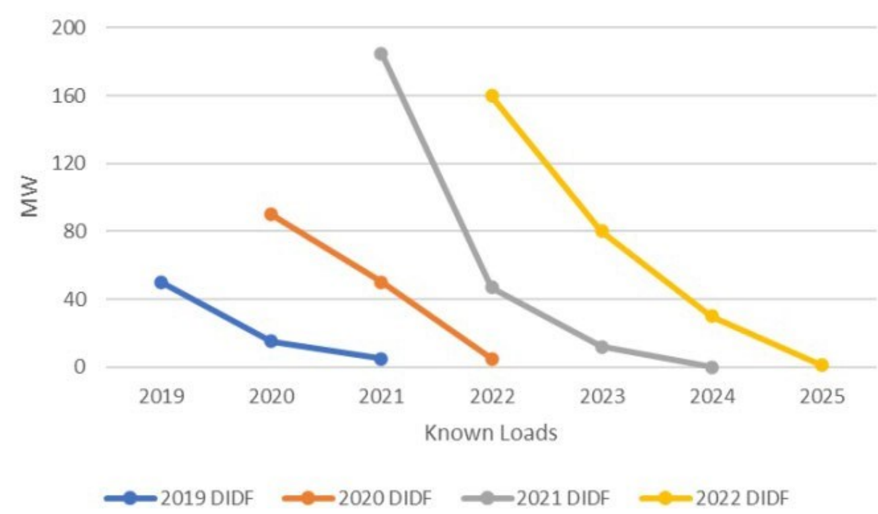
	2023	2024	2025	2026
Total Requested MW	486.3	185.2	0	1.4

Source: SCE Response to ALJ Ruling Seeking Additional Information from IOUs on Their DPP

Additionally, Figure 3-15 shows the requested capacity of commercial EV chargers as tracked over four distribution planning cycles. These known loads increase every year in every cycle, showing how quickly the loads are requesting energization. Beyond two years there are close to zero requests for capacity from commercial EV chargers.

[30] Adjusted from kVA to MW

Figure 3-15: SCE Total EV Commercial Charger Known Loads for Past Four DIDF Cycles



Source: 2023 IPE Post DPAG Report

Theoretically, there are many fleet owners who know they must comply with CARB Advanced Clean Fleets (ACF) regulations, as well as other CARB zero-emission vehicle regulations, and are creating plans to do so. These medium- and heavy-duty EVs will likely require significant load to charge, which may necessitate grid upgrades to serve. These grid upgrades may take between 1-3 years for a circuit level project and between 3-8 years for a substation level project.[31] To ensure the requested EV charging load can be energized in a reasonable timeframe, IOUs require advanced notice of fleet electrification plans. However, under the existing ACF regulations, fleet owners are under no obligation to notify utilities of their plans, increasing the likelihood of a customer encountering long waits due to the need for grid upgrades to complete a site's energization request. Additionally, while the IOUs may have ad hoc or individual approaches for working with customers who provide advanced notice of electrification plans, there is not a uniform or clear process for the IOUs to utilize that information to inform resource prioritization and infrastructure investment in advance of the need.

The IOUs are already working with customers to learn about future EV service energization requests. Pursuant to Resolution E-5247, all IOUs are required to conduct quarterly meetings with major EV service providers (EVSPs) within their service territory.[32] The purpose of these meetings is to improve communication, learn about current EVSP energization plans, share feedback to improve an IOUs' service energization efforts, and educate customers about utility energization processes. While the utilities and EVSPs have shared that these regular discussions have been helpful, additional action is still needed in gathering energization plans from customers and formalizing a process to utilize that information to plan and build infrastructure in advance of the need. The existing utility strategies are to encourage customers to submit applications so the plans can become known loads, or to rely on utility staff to unofficially

[31] Responses of PG&E, SCE, and SDG&E to Assigned Commissioners Amended Scoping Memo and Ruling Appendix A Questions to IOUs on Their Investment Planning Process.
[32] Resolution E-5247, Ordering Paragraph 10 at 34.

account for the potential developments. Utilities lack a systematic approach for considering plans with varying levels of certainty and granularity.

Continuing and expanding these coordination efforts are critical, although it is currently not clear whether these engagements are substantially effective in spurring the use of this information to influence capacity planning. We see this issue as two-fold:

1. More types of customers must engage with the utilities well in advance of their application for energization. This includes fleets, public transit electrification plans, regional electrification and transportation plans, and plans from other entities that must comply with CARB's existing and future transportation electrification regulations. While more work is needed on this issue, CPUC staff are already taking up this topic in other venues (e.g., Freight Infrastructure Planning framework, EV Infrastructure Rule implementation) and elsewhere (e.g., CEC AB 2700 implementation).
2. Utilities need a process to accept customer electrification plan information, and they need a process to utilize this customer information to inform distribution planning and investment. This is squarely in the scope of distribution planning and this proceeding.

Responsibility: Customer Issue, IOU Issue

Key Goal 1: Bringing TE loads into distribution planning early and more accurately, to the extent feasible. Utilities should use available data and outreach to create a reliable projection of transportation electrification loads before receiving specific requests for energization (in other words, before known load data is available), in the mid-term to the extent feasible. EVSPs and fleet operators should continue to work with the utilities early and often when doing their own planning. The information gathered from these coordination efforts, even in pre-application form, should be used by utilities to inform distribution planning. Staff are also working on other TE initiatives, such as the Freight Infrastructure Plan, that should be coordinated with and should inform distribution planning. Utilities should leverage this information, with direction from Staff, as it becomes available to create their load projections.

3.1.6. Delays and Long Energization Timelines: The Impact of Distribution Capacity Upgrades on Customers

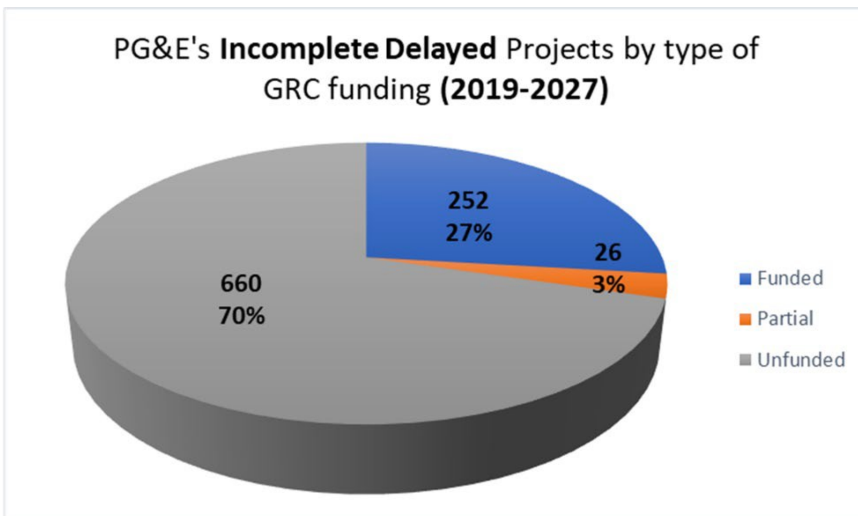
Description: Utilities have seen an increase in the size and speed of energization requests as the pace and scale of electrification has increased over time. As discussed earlier, some EV charging sites can require the amount of capacity normally needed for a small town or stadium (e.g., 5 MW). Growth in cannabis and high-tech campuses has also contributed to an increase in large energization requests. Consequently, customers have seen energization delays and long energization timelines for these projects. Utilities may not meet a customer's requested energization date for various reasons, including the need to complete distribution capacity work before a customer is energized. Only energization issues related to distribution capacity work are discussed here as opposed to downstream energization issues regarding distribution line and service extensions and upgrades.

These long energization timelines due to distribution capacity can occur because: (1) lack of available funding leading to distribution capacity project delays, currently only for PG&E; (2) customers projects trigger long-lead time capacity work that requires a timeline beyond their desired energization date, potentially pushing back energization until the capacity project can be completed; (3) delays in distribution capacity project execution, i.e. permitting, resource availability, etc., can extend project completion date and potentially delay energization.

Lack of Available Funding

PG&E is the only utility citing funding deficits. Lack of available funding can cause projects to be delayed beyond previously set energization timelines or be the provision of long-lead times for energization. PG&E's 2023 DDOR identified 277 substation and feeder projects for which there is not sufficient funding included in PG&E's 2023 GRC application. The projects without funding will not be completed within the current DPP cycle and are then carried over to future cycles leading to further delays for existing customer projects and longer than usual timelines for new customer projects. This is addressed in Section 3.2.5.

Figure 3-16: Share of Delayed Distribution Capacity Projects that are Funded



Source: IOU data from PG&E

Customer Projects Trigger Long Lead Time Capacity Upgrades That Require A Timeline Beyond Customers' Desired Energization Date

As mentioned in Section 3.1.5, traditionally, new large electric loads are associated with large construction projects that take years to be built, but EV charging depots can demand equivalent power and can be built in weeks. It is not uncommon for large energization requests, not only EV charging stations, to require a grid capacity upgrade to serve the load. Consequently, customers may receive an energization timeline beyond their desired date, because of the lengthy nature of upstream upgrades. These are not delays, although they can become delayed if a utility later extends their provided date for energization. As a practical matter, the distribution grid must be upgraded to ensure the grid operates safely. Grid upgrades, which are determined annually and reported in the DDOR, are mainly informed by requests for service, but the upgrade projects take time to design and complete. Forecasting and disaggregation improvements and proactive planning and building can decrease the likelihood of energization requests requiring a grid upgrade but cannot eliminate the possibility entirely.

Another strategy to mitigate lengthy energization timelines is to implement temporary solutions to bridge the gap in time between when a customer requests energization and when the needed distribution upgrade can be completed. Such temporary solutions can include flexible service connections, which PG&E is currently piloting, that allow customers to receive service as long as they agree to limit their energy consumption during specific peak periods, or mobile battery storage that allows the utility to supplement capacity during peak periods. These solutions can help customers operate with minimal disturbance until the distribution upgrade is complete, at which time the restrictions or mobile battery would be removed, and the customer can safely operate without interruption.

Many EVSP developers are aware of this barrier and make inquiries to the utilities to find locations on the grid with available capacity to serve EV chargers without an upgrade. However, many customers do not have the ability to change the location of their EV charger. Therefore, distribution capacity upgrades must be considered as a possibility by customers when planning for electrification, and communication to utilities ahead of time can help inform expectations and get service sooner.

Exogenous delays

Utilities have also reported delays in their project timelines coming from sources beyond their control. Utilities have cited permitting delays, land use permits and easements, environmental compliance, material delays, workforce availability, changes in project scope or design, changes in customer requirements or timeline, changes in the IEPR load forecast, resource constraints, project cost escalations, and clearance timeframes. Additionally, projects can be delayed for multiple of these reasons. Some of these are outside of the jurisdiction of both the CPUC and the utility and are therefore out of the scope of this staff proposal. Of this list, the delay sources relevant to the staff proposal are workforce availability, resource constraints, and changes in the load forecast.

Responsibility: IOU Issue, Customer Issue, Regulatory Issue

Key Goal 1: IOUs to develop strategies, such as temporary DER placement or limits on energy use as bridging solutions for energization requests that require distribution capacity projects. When a customer energization request requires a distribution capacity upgrade, utilities may be able to energize the customer temporarily, until the upgrade is completed, using temporary load flexibility via voluntary load curtailment for specific limited times or DER assets such as mobile batteries.

Key Goal 2: Improved tracking of distribution capacity project execution and related funding. The IOUs should publicly report on distribution capacity project execution and the extent to which they redirect significant funding into or out of distribution capacity work as part of their regular distribution planning reporting.

3.1.7. Cost Recovery: Load Growth Acceleration and Cost Recovery Challenges

Description: Cost recovery is a critical component of all the work IOUs conduct. The primary source of funding for IOUs is through rates, which are set through the GRC process. To ensure IOUs receive adequate funding through rates, they must bring detailed and accurate testimony in their GRC filings to prove that their requests are reasonable, useful, and necessary. Decision D.18-02-004 implemented the requirement for utilities to base their GRC testimony on the output of the DPP. In part because of issues with medium- and long-term planning (3.3.5) and issues with load forecasting (3.1.1, 3.1.2, 3.1.3), the DPP does not currently produce an accurate forecast of grid needs that matches the actual needs over the entire GRC window. Combined with the requirement that DPP outputs serve as the basis for their GRC testimony, some utilities have found it challenging to provide sufficient justification for their distribution planning funding requests.

Based on the process described above, Staff have found that improvements to the DPP and the GRC input process should allow for utilities to create more robust GRC testimony. Since the DPP is a key input into the GRC for distribution funding, upstream improvements to the DPP itself should flow down to improvements in GRC testimony and therefore the costs IOUs are approved to recover. As described throughout Section 3.2, this staff proposal aims to create a more robust distribution forecasts in the near-term due to changes in known loads and IEPR implementation (3.2.1, 3.2.2, 3.2.3), in the mid-term due to pending loads and community engagement (3.2.7, 3.2.13), and in the long-term due to disaggregation improvements (3.2.5, 3.2.6). Therefore, when the IOUs conduct their next GRC, the testimony will benefit from these improvements.

Still, these issues are underlaid by an anticipated growth in peak loads in the range of 40% by 2040. This points to the need for some measure of flexibility in cost recovery to account for higher loads causing more grid needs and thus costs in the GRC forecast. The 2018 Decision (D).18-02-004 that established the DIDF ordered that "the GNA and DDOR filed the year after a GRC filing year is inadmissible in the evidentiary record of that GRC proceeding, and may not be used to update the underpinning assumptions of the GRC testimony that was filed the previous year." The current period of ambitious policy adoption and the following forecast updates means that there can be significant differences between annual IEPR forecasts, and therefore GNAs and DDORs. Therefore, the difference between GNA/DDOR filing years can result in significantly different funding requirements. Allowing utilities to bring in the most recent data to their GRC testimony should yield the most accurate results and therefore the best outcomes.

In addition, Staff encourage utilities to use credible supplemental studies, forecasts, or other data to support their claims, while still using DPP filings as a key input to the GRC testimony. For example, SCE introduced its Transportation Electrification Grid Readiness (TEGR) analysis in its current GRC, in which SCE models more TE load growth in the near-term and is largely consistent with the 2022 IEPR over the forecast horizon. The funding request based on the TEGR asks for 86% more funding than would be derived only from the "non-TEGR" 2021-2022 DPP cycle, based on the 2020 IEPR.[33] The forecast volatility combined with the process lag to incorporate IEPR data into the DPP and then the GRC can exacerbate the discrepancy and risks underfunding necessary distribution upgrades if utilities do not bring in additional analysis.

Table 6: SCE TEGR and Total non-TEGR Projects

SCE-2 Vol.7 Capital Projects	$000's
DSP35811 Fernwood 66/12 (D) - Bank Replacement	1,678
DSP35784 State Street 66/12 (D) - Disconnect Replacement	31
DSP35801 Aqueduct 66/12 (D) - Bank Replacement and Circuit Addition	1,197
DSP35816 Ditmar 66/16 - Bank Replacement	4,483
DSP35833 50% Full TE Sub Real Properties Only, Metro East	4,749
DSP35834 50% Full TE Sub Real Properties Only, Desert	1,319
DSP35829 New 66/12 kV (D) Substation % Hinson System	125,729
DSP35807 New 33/12 kV (D) Substation % Kramer System	83,580
DSP35822 New 33/12 kV (D) Substation % Vista System	84,419
DSP35812 Mt. Tom 55/12 (D) - Bank Replacement	3,348
DSP35818 Sunnyside 66/12 kV (D) - Bank Replacement	3,257
Total TEGR	313,790
Total SCE-2 Vol.7 (ALL) [34]	677,476
Non-TEGR	363,686
Percentage increase due to TEGR	86.28%

Source: 2025 GRC SCE-02 Vol.07 Book A – Load Growth, Trans Projects, and Engineering 174-318.

Despite improvements to the DPP, it remains the case that some utilities are experiencing funding constraints in the present that improvements to future GRC cycles will not alleviate. However, during the development of this staff proposal, Senate Bill 410 (Becker, 2023) was signed into law. This bill requires the Commission to authorize a cost recovery mechanism upon 180 days of a utility's request for additional funding to cover energization costs, including upgrading distribution capacity. This mechanism will relieve the immediate funding issues utilities face. SB 410 also requires the Commission to improve the way utilities request authorized revenue requirements in their GRCs, as described above, which will relieve funding issues in the future.[35] Both these requirements align with the goals of this staff proposal detailed below.

Responsibility: Regulatory Issue, IOU Issue

Key Goal 1: Utilities can meet funding needs for distribution capacity work, currently covered by the framework described in SB 410. Utilities that need funding to cover distribution capacity projects currently identified in the distribution planning processes should be able to access that

[33] 2025 GRC SCE-02 Vol.07 Book A – Load Growth, Trans Projects, and Engineering at 92
[34] ED-SCE-001 Q1.xls "SCE 2025 GRC Data Request Response - O&M and Capital Forecasts" emailed by SCE
[35] Senate Bill 410 (Becker, 2023). Public Utilities Code 937 (d)

funding. SB 410 provides statutory direction for utilities to apply for additional funds and receive relatively quick approval.

Key Goal 2: Provide More Flexibility for Utilities to Request Distribution Capacity Costs in the GRC. Utilities should use the most up to date DPP data and data beyond annual DPP filings to justify cost estimates where reasonable. More recent data, such as newer IEPR vintages, policy mandates, and utility analysis can be leveraged to produce more robust GRC proposals, similar to the TEGR analysis that SCE has submitted in its 2025 GRC testimony.

3.1.8. Grid Modernization: Effective Utilization of DERs and Load Flexibility

Description: The energy transition, in particular transportation and building electrification, presents significant new load that the distribution grid must accommodate. This rapid load growth may require grid upgrades faster than they can be deployed. It may become increasingly necessary to employ load management and load flexibility as near-term bridging solutions to efficiently utilize existing capacity while infrastructure is built. In the long term, given the magnitude of expected electrification-related load, flexible loads may be a resource of significant scale with the potential to mitigate distribution infrastructure cost.

At present, the most common type of DER for this application are battery energy storage systems (BESS or battery). These batteries can be either customer owned BTM batteries that can be contracted with utilities or 3rd party aggregators, or utility-owned FTM resources which are typically much larger than BTM counterparts. Additionally, it is likely that electrified smart appliances such as heat pumps and water heaters will be able to be coordinated for grid benefit be preheating or precooling before peak demand periods and reducing usage during them. The same coordination may also become premise-wide using smart electric panels which can coordinate across an entire building's electricity usage. While these more advanced appliances are yet to be widely adopted, coordinated battery programs such as Virtual Power Plants (VPPs), are already operational on small scales by community choice aggregators (CCAs) and third-party DER aggregators.

The current distribution grid largely leaves DERs as isolated devices that provide a service to the customer and sometimes to one other need, such as a DIDF deferral need or a third party DER aggregator's program. To manage the energy transition effectively and promote DER adoptions and behaviors critical to achieving state goals, the distribution grid should utilize BTM and FTM grid assets dynamically and effectively to reduce local demand.

Responsibility: IOU Issue

Key Goal 1: Prepare Utility Distribution Planning and Project Execution for Grid Modernization. Load management capabilities and DER Management Systems (DERMS) have the potential to coordinate utility- and customer-owned batteries and smart appliances to smooth load curves and lower peak demand across a circuit to increase effective capacity. These technologies may be important bridging solutions during this transition period if distribution upgrades are needed on short notice before utilities can construct them. Utilities should be prepared to adopt frameworks and technologies to modernize the grid to be an integrated, dynamic system that produces local and system wide benefit by effectively utilizing grid assets to maximize capacity usage, defer or eliminate grid upgrades, provide enhanced reliability and clean energy, and coordinate system efficiencies.

3.1.9. Community Engagement: Coordination and Engagement with Local and Tribal governments, Planning Agencies, ESJ Communities, and Local Developers

Description: Outreach conducted in Fall 2022 for the Distribution Planning Community Engagement Needs Assessment Study revealed communities' lack of visibility into IOUs' distribution planning and a desire for greater partnership among local energy producing entities. Furthermore, California's IOUs lack a unified method of community and tribal engagement for distribution planning, which hinders effective communication and partnership and compromises the incorporation of local and tribal interests into these key planning processes.

Information on local development plans, in particular plans for electrification, may also be a useful input into distribution planning. Local planning entities, as well as EVSP or other private institutions with growing electrical energy needs, often have various plans for future development that have not yet reached the stage of an actual application for energization. The IOUs should not consider these plans as guaranteed but should consider the likelihood these plans will materialize and balance that likelihood against the cost of potential upgrades.

Responsibility: IOU Issue

Key Goal 1: Effective IOU coordination with local planning entities. The IOUs should engage with local planning entities, such as local governments, and developers in two-way dialogue so that the IOUs are aware of planned development and load increases for consideration in their distribution planning and stakeholders are aware of utility plans. The IOUs should also encourage early energization requests so that any needed upgrades can be planned within existing processes. The IOUs should develop a process to incorporate early engagement with local governments, customers, developers, and fleets into the distribution planning process.

3.1.10. Equity: Equity Considerations in Distribution Planning

Description: Historically, utility distribution planning has been a largely reactive process that is primarily concerned with responding to customer requests for service. It is neutral as to where the load growth is coming from, who is requesting it, and what it is for. However, in the process of creating distribution forecasts and plans, biases can appear unintentionally. Propensity modeling, for example, considers historical energy use and demographic characteristics such as household income to forecast future energy use. SCE, for example, chose one metric to be the key propensity indicator for EV capacity in the 2022-23 DIDF cycle: the number of households in a ZIP code with income over $150,000.[36] This type of analysis tends to bias forecasted capacity

[36] SCE's *2023 Grid Needs Assessment & Distribution Deferral Opportunity Report* at 22.

allocation to wealthier neighborhoods. While the analysis may be effective for some use cases, it does not reflect the Commission's commitment to equity. The Commission has many equity-focused programs to facilitate the adoption of clean energy across the state, but they will be unsuccessful if the distribution system is not coordinated with them and prepared to accommodate them. Staff acknowledge this can be a challenging task. Funding alone does not guarantee that equity driven EV infrastructure will be deployed as equity programs face implementation obstacles even when funded.

Responsibility: Regulatory Issue, IOU Issue

Key Goal 1: Proactively consider equity as a priority in distribution planning. To ensure that the energy transition does not inadvertently leave vulnerable communities behind, equity must actively be considered in the DPEP. The inputs, methodologies, and outputs of the DPEP should be evaluated for their impact on equity. The DPEP should be coordinated with existing equity programs to ensure they are accommodated.

3.1.11. Project Prioritization: Improving Project Prioritization when the Prioritization is Useful or Necessary

Description: The way utilities prioritize the construction of their grid upgrades is not transparent or consistent. In general, SCE and SDG&E use the "need date" - the date the project needs to be completed to mitigate an overload – as their prioritization criteria. This prioritization method works well if projects are not delayed past their need dates. SCE and SDG&E, in general, "do not reprioritize or delay distribution capacity projects."[37] If SCE or SDG&E do not have sufficient budget to complete distribution capacity work, they "attempt to modify budgets to enable completion of DPP work."[38] This strategy works well, as they report having no projects delayed solely due to lack of funding. The high-level method that SCE and SDG&E use does not prioritize between projects, but between workstreams by shifting money in order to complete all projects before the need date.

In most cases, utilities should be constructing a project in time to meet a need date and should not need to further prioritize between projects. However, in some cases, a more detailed prioritization framework may be useful or even necessary. If distribution planning can reliably identify needed long-term projects, these could be prioritized for early completion in order to spread out workloads or bundle capacity upgrades with other distribution work. Alternatively, if an IOU does not have adequate funding to complete all distribution projects, such as PG&E currently claims, certain projects will have to be selected to pursue before others. Criteria to determine which projects to accelerate will aid in prioritization. Prioritization also provides opportunities to increase the equitable outcomes of distribution planning such as the allocation of load and generation capacity on the grid.

[37] Southern California Edison Company's Supplemental Responses and Comments to Assigned Commissioner's Amended Scoping Memo and Ruling, Appendix A at 8
[38] Southern California Edison Company's Supplemental Responses and Comments to Assigned Commissioner's Amended Scoping Memo and Ruling, Appendix A at 9

Responsibility: IOU Issue

Key Goal 1: Improve prioritization under constrained funding. PG&E has reported that due to lack of adequate funding through the GRC there are over 600 unfunded projects in its territory. PG&E currently uses a 3-tier prioritization framework: (1) projects that are near completion, mitigate safety risks, and/or can be combined with other work, (2) projects that connect waiting customers, and (3) projects that reflect organic, distributed load growth, in that order.[39] PG&E also stated that projects not completed on time are considered "carry-over" work to the next year and assigned high priority for future funding. PG&E should prioritize completing projects in a first-in-first-out system, energizing customers who have been waiting the longest first. PG&E should also seek efficiency by prioritizing projects that can meet multiple needs at once. In the long run, PG&E should ensure that distribution planning has adequate resources, such as employees and/or contractors, to complete all distribution work in a timely manner (See section 3.1.7 above).

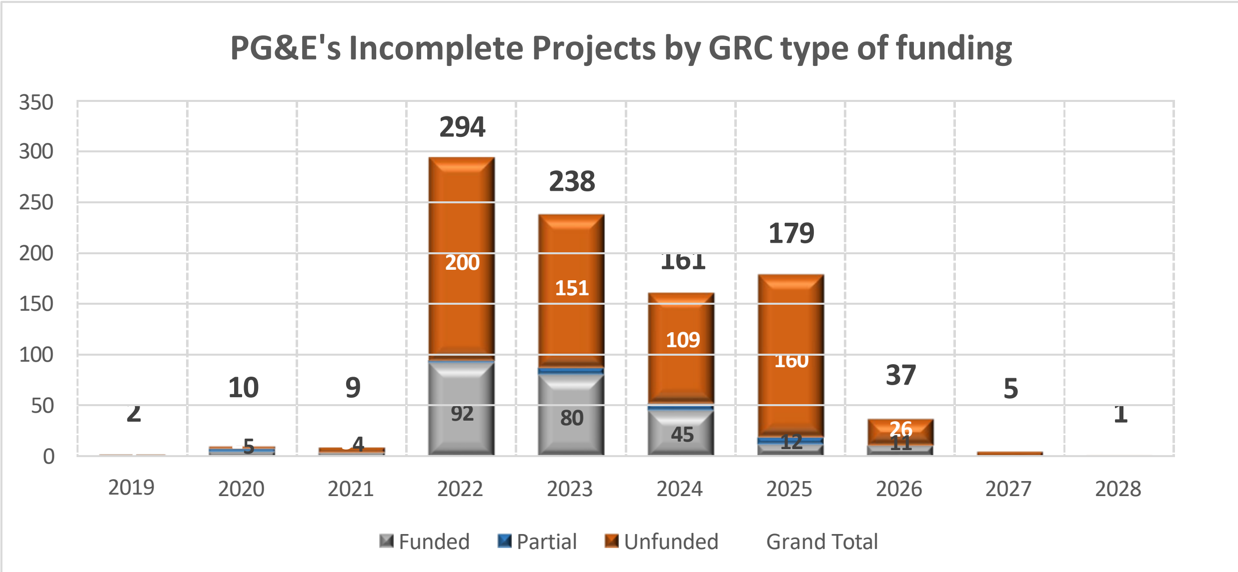
Table 7: PG&E Project Data by Region

Region	# of Projects	% of total	# of Unfunded Projects	% Unfunded Per Region	# of Tier 2 Projects in Region	% of Projects in Region that are Tier 2
Bay Area	137	13.99%	75	54.74%	91	66%
Central Valley	446	45.56%	319	71.52%	170	38%
North Coast	100	10.21%	67	67.00%	65	65%
North Valley and Sierra	125	12.77%	85	68.00%	47	38%
South bay and Central Coast	171	17.47%	115	67.25%	81	47%
TOTAL	979	100%	661		454	

Source: IOU data from PG&E

[39] Responses to Amended Scoping Memo Appendix A by PG&E Company at 16

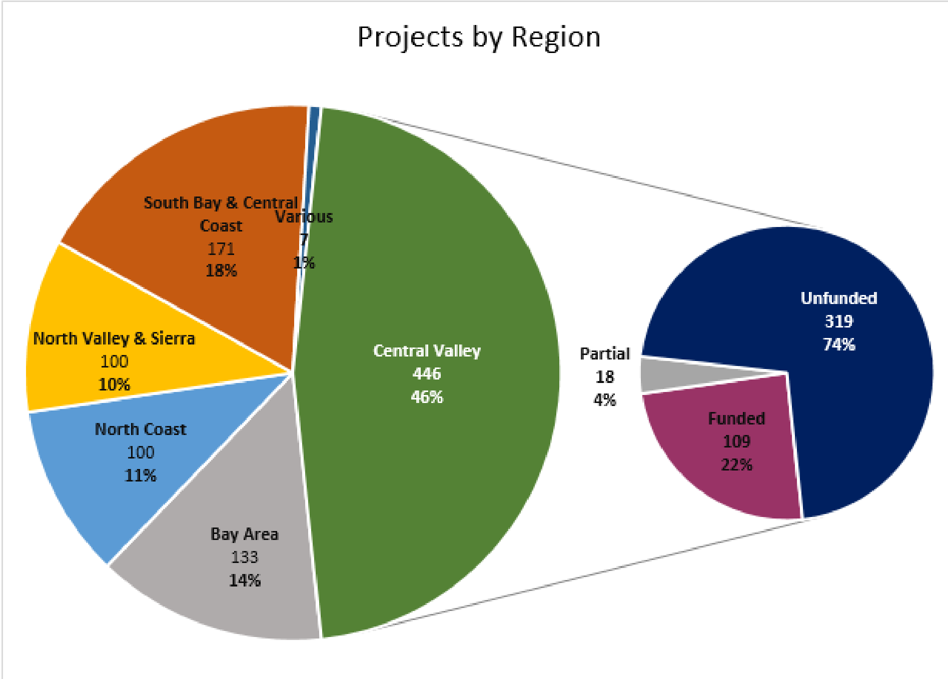
Figure 3-17: Share of Projects by GRC type of funding and expected year of operations.



Source: IOU data from PG&E

Key Goal 2: Incorporating equity considerations into prioritization. In PG&E's territory, the Central Valley has 46% of total projects (446 out of 957), with 74% of these projects unfunded. As shown in Table 7, this is the region with the most total projects and the highest percentage of unfunded projects. This is consistent considering the project prioritization framework described above because only 38% of the projects in the central valley are categorized as PG&E MAT codes 06H and 46H, which are associated with customer requests and is a good indicator that they fall into Tier 2. Therefore, 38% of projects are assigned to tier 2, while the majority of the rest of the projects are due to organic load growth and assigned to tier 3 in PG&E's current prioritization framework. There are many low priority projects in the Central Valley that may be or become delayed and may be difficult to address in a timely fashion if a customer were to request load in that area. This is concerning considering the amount of the Central Valley that is considered low income and disadvantaged. It seems, then, that PG&E's investment prioritization framework may be inadvertently producing inequitable outcomes when choosing which projects to fund. Equity should be incorporated into prioritization, or prioritization methods should be reviewed with equity in mind.

Figure 3-18: Share of Projects by Region, Showing Significant Unfunded Projects in Central Valley



Source: IOU data from PG&E

Key Goal 3: Prioritizing the acceleration of future projects. SCE has expressed concerns that electrification-related load growth may lead to many substations requiring upgrades within a short period of time, requiring concurrent work to complete the projects before their need dates. Substation projects typically take between 5-10 years and require significant resources. Should many projects need to happen concurrently, utility workforces may be unable to fulfill the entire workload. To avoid this outcome, to the utilities should prioritize long-term projects that are needed with high levels of certainty. Extending the horizon for distribution planning and improving the methods for mid and long-term forecasting and disaggregation should (1) reveal the extent to which work should be spread out to mitigate workforce or other concerns and (2) clarify which projects are higher certainty and might be prioritized for early completion.

3.2. Proposals Related to Distribution Planning and Execution

In this section, Staff present various proposals to improve utility distribution planning and execution. Each proposal is tied to certain issues and key goals from section 3.1 above. The proposals generally aim to direct the utilities to act, for example by requiring the development and submission of proposals to improve current processes in ways that do not hinder flexibility and improvement in the future. The proposals also respond to all of the distribution planning-related requirements in SB 410 and AB 50, as described in Table 8 below.

Table 8: Summary of Proposals Related to SB 410 and AB 50 Requirements

Bill	Public Utilities Code (PUC) Section	Summary of Requirement	Proposals that meet the Requirement
SB 410	936 (a) (1)	Commission shall require utilities to consider the following in their annual DPPs: (1) Federal, state, regional, and local air quality and decarbonization standards, plans, and regulations; (2) The transportation and building electrification policies of state law; (3) State agency, local agency, and local government plans and requirements related to housing, economic development, critical facilities, transportation, and building electrification; (4) Known load, and projections of load provided by the Energy Commission; and (5) Projections of load that exceed forecasts provided by the Energy Commission.	(1), (2) and (4) are already included in utilities DPP through the use of IEPR forecasts and known load data. Proposals 3.2.1, 3.2.2, 3.2.3, and 3.2.7 improve these processes. Proposals 3.2.1 and 3.2.7 meet requirement (5). Proposal 3.2.13 meets requirement (3).
SB 410	936 (a) (2)	Commission shall require utilities to adopt and implement plans (1) to satisfy the state policies listed in PUC Section 933, such as upgrading the distribution system as needed and in time to achieve decarbonization and air quality goals, and conducting advance planning, engineering and construction so that customers can be energized without substantial delay; (2) to support achieving the requirements from 936 (a) (1) above; and (3) to generally meet the energization time periods required by PUC Section 934.	Proposals 3.2.2, 3.2.5, 3.2.6, 3.2.7, 3.2.10, 3.2.13 all require utilities to develop, adopt and implement plans that meet these requirements. Proposal 3.2.4 also requires extending the distribution planning horizon to 10 years.
SB 410	937 (d)	(d) The commission shall ensure that each electrical corporation improves upon energization planning, consistent with the requirements of Section 936, when requesting an authorized revenue requirement during the electrical corporation's general rate case, in order to minimize the need for any ratemaking mechanism authorized pursuant to this section.	Proposal 3.2.12 directly improves the process of requesting an authorized revenue requirement in their GRC. Proposals 3.2.1, 3.2.2, 3.2.3, 3.2.5, 3.2.6, 3.2.7, 3.2.13 all improve the DPP which is a key input to utility GRC testimony.
AB 50	933.5 (c) (1)	To improve the accuracy of projected demand and facilitate achievement of the goal of timely electric service through energization, each electrical corporation shall evaluate and update,	Proposals 3.2.1, 3.2.2, 3.2.3, 3.2.4, 3.2.5, 3.2.6, 3.2.7, 3.2.13 meet this requirement.

		as necessary, its existing distribution planning processes.	
AB 50	933.5 (c) (2)	To improve the accuracy of projected demand, each electrical corporation shall have annual meetings with interested parties and experts in customer energization, including representatives from local governments and the relevant county staff for each interested county in its service territory, which is presumed to include chief administrative officers, planning directors, public works directors, chief building officials, and economic development officials, to discuss relevant information, which may include, but is not limited to, customer service, existing capacity, planned capacity upgrades, projected local demand, local development plans, significant delays in customer energization in the county, distribution planning, existing workflows, and potential improvements to planning, timelines, processes, and customer communication and education.	Proposal 3.2.13 meets this requirement.
AB 50	933.5 (c) (3)	To increase the pace and scale of local projects intended to meet state, regional, and local housing and economic development objectives, each electrical corporation shall share relevant information, which may include, but is not limited to, data available through the integrated capacity analysis tool, upon request with local governments about those areas where existing capacity either exists or could be easily added, and where existing capacity is planned to be added, within the distribution system to meet those objectives. Local government employees authorized to request information include chief administrative officers, planning directors, public works directors, chief building officials, economic development officials, and city managers.	Proposal 3.2.13 meets this requirement.

3.2.1. Allow Utilities to use Bottom-Up, Known Load Data to Determine Load Growth

Related Issues and Goals: Issue 3.1.2: Planning Process, Key Goal 2

Related Legislation: SB 410: PUC Section 936(a)(1); AB 50: PUC Section 933.5(c)(1)

Party Comments:

SCE recommended reducing focus on disaggregation of a system level forecast and increasing focus on bottom-up forecasting methodologies, as SCE has done in the TEGR analysis for its 2025 GRC, due to the apparent misalignment between the IEPR and known loads in the early years of the forecast and MH/HD TE loads.[40]

Other parties noted issues with the current use of the IEPR and supported expanding bottom-up planning.[41, 42, 43, 44]

Commission Action: The Commission should allow the IOUs to use reliable bottom-up data to estimate total load growth in a given year, even if it exceeds the forecasted load growth based on the IEPR for that year. In years without reliable bottom-up data, total growth should correspond to the forecast amount and not be adjusted downwards.

Rationale:

- As noted in section 3.1.2, bottom-up known load data, and other similarly reliable near-term data on load growth, should be used to estimate load growth at the circuit level in utility distribution planning when available. Using this reliable, near-term data should not distort the use of IEPR forecasts in later years, as it currently does in all IOU processes. Similarly, utilities should not shift known load data to later years in order to adhere to the annual IEPR forecast capacity allowance, as SCE historically has.

Tentative Timeline: Next DPP Cycle

Additional Questions for Stakeholder Consideration:

1. How should 'reliable bottom-up data' be defined? To what extent should the Commission determine this process versus allowing the utilities to determine it using their own judgment and expertise?

3.2.2. Utilities to Improve Method for Setting Caps on Load Growth from IEPR Data

Related Issues and Goals: Issue 3.1.2: Planning Process, Key Goal 1

Related Legislation: SB 410: PUC Sections 936(a)(1) and 936(a)(2); AB 50: PUC Section 933.5(c)(1)

Party Comments: No parties commented directly on this issue in response to past rulings, though some parties noted issues with the current use of the IEPR.

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[40] SCE Comments to ALJ's Ruling Directing Responses to Acquisitions on Track 1 Phase 1 at 24
[41] Clean Coalition Comments in Response to ALJ's Ruling Directing Responses to Questions on Track 1 Phase 1 at 9
[42] SCE Comments to the ALJ's Ruling Seeking Additional Information from IOUs on their Distribution Planning Process at 17
[43] Green Power Institute Opening Comments on ALJ's Ruling at 4
[44] Opening Comments of [Joint CCAs] responding to Questions on Track 1 Phase 1 at 6

Commission Action: The Commission should direct the IOUs to submit proposals via Tier 2 Advice Letter for how they will improve their methods for setting caps on load growth based on the IEPR forecasts and other data.

In the long term, these plans should describe how the IOUs will move toward using IEPR data in a way that is directly comparable between the system and the circuit level. For example, studies on non-coincident load peaks and analysis of energy usage may indicate methods to produces data that is more directly comparable, e.g. using the IEPR *energy* forecasts as the basis for modelling, disaggregating new energy needs to the circuit level and then modelling the capacity needs of each circuit based on this added energy and appropriate load curves.

In the near term, IOUs may propose and enact temporary adjustments to their current methods that aim to account for differences between circuit-level peak loads and system-wide peak loads, and/or any other potential differences between the IOU's current estimates and actual load growth that can be both theoretically grounded and shown in concrete data. These near-term proposals can be enacted immediately and then updated once the ALs are approved.

Rationale:

- As noted in section 3.1.2, the way the IOUs apply IEPR-based capacity forecasts to distribution planning can underestimate actual circuit peak loading across the system, and similarly underestimate these year-over-year growth caps. This underestimation would inhibit distribution forecasting and planning.
- In the long term, the IOUs should move toward methods that do not underestimate load growth. However, ongoing distribution planning should also be adjusted where reasonable to make current load growth estimates more realistic.

Tentative Timeline: Next DPP Cycle, Advice Letter in 2024

3.2.3. Provide Flexibility on which IEPR Vintage Utilities Can Use in Distribution Planning and Develop Methodology for Incorporating Newer IEPR into Existing Planning

Related Issues and Goals: Issue 3.1.1: Planning Process, Key Goal 1

Related Legislation: SB 410: PUC Section 936(a)(1); AB 50: PUC Section 933.5(c)(1)

Party Comments: Multiple parties noted that the use of older IEPR forecasts in distribution planning can lead to issues with forecasts, particularly when significant policy or other changes affect the IEPR. [45, 46]

SDG&E proposed a process that would allow for the use of a 1-year newer IEPR in the DPP.[47]

Commission Action: The CPUC should allow utilities to update the forecast used in distribution planning with an equivalent forecast from a newer IEPR.

Additionally, each IOU should include an evaluation of how the newest IEPR data can be incorporated into distribution planning in their next DDOR report. This evaluation should consider how late in the distribution planning process forecasts from the IEPR can be effectively used as an input, and whether the IEPR forecasts can be brought in after the load disaggregation process, with the goal of using the newest possible IEPR forecasts within distribution planning.

Rationale:

- Although it made sense to include review and approval of the IOUs growth forecasts and related scenarios in 2018, when the DIDF process was first created, it has now become a familiar step within distribution planning. In the years since 2018 the IOUs have sought approval for specific IEPR forecasts, and that approval has never been denied or significantly modified. Five years later, it is reasonable to allow newer data to be brought in without further approvals.
- As noted in Section 3.2.1 above, the use of outdated IEPR forecasts has a negative effect on distribution planning and should be avoided if possible. To this end, the CPUC should remove requirements that make the process of incorporating newer IEPR data slower and less flexible, and the IOUs should develop plans to use newer IEPR data where feasible.

Tentative Timeline: Next DPP Cycle

3.2.4. Utilities to Expand the DPP Forecast Horizon to Align with the IEPR and Expand the Planning Horizon to 10 Years (Maintaining the Horizon for Project Deferral at 5 Years)

Related Issues and Goals: Issue 3.1.4: Coordination and Planning, Key Goal 1, Key Goal 2

Related Legislation: SB 410: PUC Section 936(a)(2); AB 50: PUC Section 933.5(c)(1)

[45] PG&E Answers to ALJ Ruling Seeking Additional Information on the Distribution Planning Process at 25
[46] UCAN Comments to ALJ's Ruling on April 6, 2023 Requesting Responses to Questions on Track 1 Phase 1 at 5
[47] SDG&E Response to ALJ Ruling Seeking Additional Information from Investor-Owned Utilities on their Distribution Planning Process at 9

Party Comments: The IOUs and other parties generally agreed with extending the forecast and planning horizon.

PG&E proposed a 10-year horizon for distribution planning and a 13-year horizon for forecasting. A 5-year horizon would still be applied for DIDF procurement purposes. This aligns with their current practice, although they do not report on grid needs beyond 5 years (currently).[48]

SCE currently uses a 10-year planning horizon and noted a longer time horizon will be critical in planning for TE load growth. It proposes to begin assessing needs out to 20 years.[49]

The Public Advocates Office stated that a 10-year planning horizon is inconsistent with state policy goals and a 20-year planning horizon may be more appropriate.[50]

SDG&E points out that there is currently no restriction on utilities expanding their planning horizons. This allows utilities to utilize the whole 13-year IEPR horizon to assess anticipated loads.[51]

Commission Action: The IOUs shall extend their distribution planning forecast horizons to a minimum of 13 years (corresponding with the 15 years of the IEPR forecast minus the current two-year delay in incorporating the IEPR data into distribution planning) and shall extend their planning horizon to a minimum of 10 years. This means that the GNA, the DDOR, and any related reports should include at minimum a 13-year forecast and planned projects for the following 10 years. Beyond 5 years, the IOUs do not need to conduct a full power flow analysis to evaluate all grid needs but can simply evaluate thermal capacity needs by assigning load growth to specific circuits, substation banks, and other key assets, or use another simplified method at their own discretion.

The 5-year planning horizon for DIDF procurement purposes will be maintained at 5 years and will not be extended.

Rationale:

- Utilities already can, and routinely do, forecast and plan beyond their typical horizon. As shown in Table 3 in section 3.1.4, PG&E and SDG&E include a "5+" year planning horizon for substation projects, indicating that they look beyond 5 years when they deem it necessary. As electrification increases across the state, this practice should be made standard system-wide to inform impending workload, sourcing, and costs, among other workstreams.
- The significant projected increases in load due to transportation and building electrification create the need to plan for electric loads further out in the future. These large loads will vary geographically and lead to acute local capacity constraints. Many of these TE dependent capacity constraints are outside of the

[48] PG&E response to ALJ's Ruling Directing Responses to Questions on Track 1 Phase 1 at 8
[49] SCE response to ALJ's Ruling Directing Responses to Questions on Track 1 Phase 1 at 8
[50] Comments of the Public Advocates Office on ALJ Ruling Directing Responses to Questions on Track 1 Phase 1 at 7
[51] SDG&E Response to ALJ Ruling Directing Responses to Questions on Track 1 Phase 1 at 6

current planning horizon, creating the concern that the magnitude of the projects may be too large to address in time once they enter the planning horizon.

- Additionally, to support anticipated load growth, substation expansion and new substation construction will be needed, both of which are long lead time projects that will need to begin sooner than the current 5-year planning horizon.
- A longer forecast and planning horizon will allow for better integration between distribution capacity work and other distribution work. For example, an undergrounding project could refer to expected loading 10 years in the future to confirm whether higher capacity conductor should be installed.

Tentative Timeline: Next DPP Cycle

3.2.5. Utilities to Improve Forecasting and Disaggregation with Scenario Planning

Related Issues and Goals: Issue 3.1.3: Planning Process, Key Goal 2; Issue 3.1.4: Coordination and Planning, Key Goal 1, Key Goal 2

Related Legislation: SB 410: PUC Section 936(a)(2); AB 50: PUC Section 933.5(c)(1)

Party Comments:

- PG&E supports the addition of sensitivity analysis in the DPP forecast for inclusion in the GNA in 2024. The results will manage uncertainty for long lead time planning and guide distribution engineers but will result in one set of solutions and therefore not be reported in the DDOR.[52] PG&E reports working on developing technical capacity for scenarios for forecasting and planning in the 2023 GNA section 2.12.[53]
- SCE supports limited incorporation of scenarios that consider high unaccounted-for TE loads in specific geographic areas to modify the original scenario base load, as SCE has conducted in the TEGR. This analysis will be expanded to consider variations in DER adoption and behavior in specific geographic areas.[54]
- SDG&E does not support obligatory DPP scenario development because it would be overly intensive and local demand is already captured by known loads.[55]
- Other parties vary in support for additional scenarios in the DPP. The Public Advocates Office provided a long-term vision of how scenarios can be used to create dynamic plans.[56, 57] There is general support for the IEPR continuing to be

[52] PG&E Responses to ALJ's Ruling on Track 1 Phase 1 Questions at 4
[53] 2023 Grid Needs Assessment of PG&E Company at 13
[54] SCE response to ALJ's Ruling Directing Responses to Questions on Track 1 Phase 1 at 7
[55] SDG&E Response to ALJ Ruling Directing Responses to Questions on Track 1 Phase 1 at 4
[56] Comments of the Public Advocates Office on ALJ's Ruling Directing Responses to Questions on Track 1 Phase 1 at 3
[57] Anna M. Brockway et al., Climate-aware decision-making: lessons for electric grid infrastructure planning and operations, June 28, 2022 (Brockway et al.)

the starting point of the DPP[58, 59], maintaining alignment with other planning processes such as GRC, TPP, and IRP, the increased importance of bottom-up planning [60], and using some additional analysis to mitigate forecast uncertainty.[61]

Commission Action: Direct the utilities to conduct forecast scenario planning in the DPP forecast and report the results in the GNA. In the near term, utilities shall conduct a sensitivity analysis that results in multiple grid need assessment outputs that are used by distribution planning engineers to create one set of solutions reported in the DDOR. To establish capabilities, utilities shall develop two alternate forecast scenarios to include in the 2025 GNA as follows:

- Low (Forecast Scenario 1)
- Mid (Grid Needs Forecast)
- High (Forecast Scenario 2)

The "Mid" scenario will be the basis for the planning scenario that is reported in the DDOR, with adjustments informed by the "low" and "high" scenarios. The utilities shall be transparent about the inputs into the forecast scenarios and justify their decisions in a new GNA section.

The utilities shall present at a workshop on forecast scenario planning to discuss the barriers and feasibility of transitioning the planning process to a fully scenario-based planning process in which multiple scenarios can be conducted to evaluate the impacts of different levels of demand, DER adoption, and customer behaviors, and how the scenarios will be integrated into a single least-regrets investment plan. Following the workshop, the utilities shall submit a Tier 2 Advice Letter that (1) summarizes the workshop, (2) draws lessons from the workshop, and (3) identifies the steps to be taken to facilitate the transition to using scenarios and a timeline for achieving them.

Rationale:

- The use of forecast scenarios in utility DPPs will provide a better picture of the likelihood that forecast grid needs will actually occur, especially in the later forecast years. If a grid need occurs under multiple forecast scenarios, it is more likely to materialize. Similarly, where a scenario shows significantly different grid need results than the base forecast, the proposed solution to the grid need may need to be resized or modified.
- The likelihood of grid needs actually occurring can be used in integrated planning and project prioritization.

[58] Reply Comments of the CAISO Corporation on ALJ's Ruling Directing Responses to Questions on Track 1 Phase 1 at 1
[59] Green Power Institute Opening Comments on ALJ Ruling Directing Responses to Questions on Track 1 Phase 1at 4
[60] Clean Coalition Comments in Response to ALJ's Ruling Directing Responses to Questions on Track 1 Phase 1 at 9
[61] Center for Biological Diversity, The Climate Center, 350 Bay Area, Vote Solar, Sierra Club and The Clean Coalition Opening Comments on ALJ's Ruling Directing Responses to Questions on Track 1 Phase 1at 20

Tentative Timeline: 2025 GNA

3.2.6. Utilities to Improve Disaggregation Methodology for Load Growth Currently Based on Economic Modelling

Related Issues and Goals: Issue 3.1.3: Planning Process, Key Goal 2, Issue 3.1.4: Coordination and Planning, Key Goal 1, Key Goal 2

Related Legislation: SB 410: PUC Section 936(a)(2); AB 50: PUC Section 933.5(c)(1)

Party Comments: No parties commented directly on this issue in past rulings.

Commission Action: The CPUC should require the IOUs to submit plans for improving their load and DER disaggregation in later forecast and planning years via a Tier 2 Advice Letter. These plans should consider modeling thermal capacity constraints without full power flow analysis, and instead using statistical methods such as Monte Carlo analysis to better approximate the probability that future load growth may lead to grid needs and related distribution capacity projects. The IOU plans must propose specific improvements for implementation in the 2025 GNA but may combine current economic modelling with new methods. In advance of submitting these plans, the IOUs should meet with Staff to discuss the draft plans and receive feedback.

Rationale:

- Although the IEPR produces reliable system level forecasts for total load growth, there is no reliable way to determine the exact premise, circuit, or substation where new load or DERs will appear in later forecast years. As discussed in Section 3.1.3 above, the IOUs currently adapt to this reality by spreading out forecasted load among circuits according to economic modelling, even though new load (for example, a new EV charging station or new development) often appears in large discrete amounts at specific locations on the grid. Statistical methods currently exist to model similar phenomena, where overall change occurs through a partially random set of discrete changes. Monte Carlo analysis, for example, can use computing power to transform stochastic models that describe a sequence of specific events into reliable probabilities of whether a certain condition will be met. In terms of distribution planning, Monte Carlo analysis can transform a model that semi-randomly generates potential new loads applying for energization into a probability that the thermal limit on any specific circuit or substation bank is exceeded in any specific year. Because of the computational complexity of power flow analysis, statistical methods that require thousands of different runs are not currently possible in grid planning without excessive cost and effort. However, for simplified forecasting in the mid- and long-term that avoids power flow analysis, these statistical methods should be possible, relatively inexpensive, and effective.

- Given that these sorts of methods are available, and that a reliable mid- and long-term load forecast and disaggregation allows for better integration with other distribution work (i.e. wildfire and asset repair work) and better planning for the significant number of distribution capacity projects that may be needed with transportation and building electrification, the IOUs should consider these methods and propose plans for improving their current disaggregation methodology.
- As discussed in section 3.1.3 above, projects that respond to grid needs related to reactive power, power quality, or voltage deviations can generally be completed with quick lead times and relatively low costs, such as adding a new capacitor bank to a feeder or substation. In the mid- and long-term, the main concern is (1) identifying increased capacity needs to facilitate integrated planning and (2) identifying long lead time projects to facilitate project management. For these later years, it is reasonable to use simple modelling methods instead of full power flow analysis, even though they cannot identify voltage deviations or reactive power needs.

Tentative Timeline: Advice Letter in 2024

3.2.7. Utilities to Create a 'Pending Loads' Category in DPP

Related Issues and Goals: Issue 3.1.3: Planning Process, Key Goal 1; Issue 3.1.5: TE Growth, Key Goal 1

Related Legislation: SB 410: PUC Sections 936(a)(1) and 936(a)(2); AB 50: PUC Section 933.5(c)(1)

Party Comments:

SCE's DPP includes a method of ranking the certainty of known loads, which has been used to prioritize the timing up of distribution upgrade projects.[62]

The Joint CBOs recommend utilities integrate state agency funding decisions into distribution planning.[63]

Many parties have commented on advanced forecasting of TE loads, similar to the pending load proposal here.[64,65,66,67]

[62] 2023 Grid Needs Assessment and Distribution Deferral Opportunity Report of SCE at 40
Also see 2023 Independent Professional Engineer Final IPE Post DPAG Report at 10
[63] Center for Biological Diversity, The Climate Center, 350 Bay Area, Vote Solar, Sierra Club and The Clean Coalition Opening Comments on ALJ's Ruling Directing Responses to Questions on Track 1 Phase 1.
[64] Comments of The Coalition of California Utility Employees on Track 1 Phase 1 Questions at 2
[65] PG&E Responses to ALJ Ruling Directing Responses to Questions on Track 1 Phase 1 at 23
[66] Opening Comments of the Joint CCAs Responding to Questions on Track 1 Phase 1 at 11
[67] Clean Coalition Comments in Response to ALJ's Ruling Directing Responses to Questions on Track 1 Phase 1 at 21

Commission Action: The Utilities should develop and implement a Pending Loads category in their distribution planning. Pending Loads are a proposed category of load that is less certain than a 'known load,' A.K.A. a customer request for service, but more certain than economic disaggregation of the IEPR forecast based on trends. The purpose of creating this category is to increase utility awareness of **where** load will likely appear in the mid-term years of the DPP without known loads, as described in Section 3.1.3. The goal of the Pending Loads category should be to estimate future load growth from any source outside of known loads in a way that balances the reliability of current information with the importance of proactive planning and investment.

Implementation of the Pending Loads category would include at minimum estimates of likely load growth tied to specific circuits or substation banks in the mid-term (roughly defined as years 2 to 5) outside of existing Known Loads. Utilities can produce these estimates based on any information gathered from coordination and engagement efforts with customers, especially concerning electrification plans, and other relevant and reliable sources. Pending loads may be used to inform upgrades to primary distribution infrastructure including new or upgraded circuits, new or upgraded substation banks and substations. Pending loads are not intended to inform the energization of an actual customer prior to an application for service, or smaller upgrades that can be completed within a year. Additionally, at this time Staff do not consider pending loads to be sufficiently "reliable bottom-up data" to be eligible justification for exceeding the IEPR load growth cap as proposed in Section 3.2.1. As the pending loads category develops, Staff thinking about this may change.

No method exists to perfectly predict where future load will show up, so any proposed method for producing pending loads must balance this uncertainty and the risk of overspending. These pending loads may be determined through multiple different methods, as long as they are justified. For example, utilities might:

- Note that a number of different customers have expressed interest in energizing new load in a given area, and on that basis assign some discounted new load to the related circuit or substation, recognizing that not all loads may materialize.
- Note that a circuit or substation serves a specific customer with an electrification plan, such as a port, and assign load with an appropriate discount factor to that location.
- Conduct a statistical analysis arguing that there is a high likelihood of at least some amount of load growth on a circuit or substation and assign new load accordingly.

In order to develop this Pending Loads category, utilities must hold a public workshop within 60 days of decision issuance to discuss how to gather energization plans from customers and other relevant information, and how to formalize a process to utilize that information to plan and build infrastructure in advance of specific energization requests, including what metrics and criteria to use, and how to judge certainty, prioritize and/or discount pending loads. Utilities must invite relevant stakeholders including those outlined in AB 50 section 933.5, local governments, developers, technical experts, policy experts, CEC staff, and other subject matter experts. Within 40 days of the workshop, utilities shall jointly produce a workshop report that captures the main points from the workshop sent to the service list and filed on the High DER proceeding Docket.

Within 60 days of the workshop, each IOU shall propose, via a Tier 2 Advice Letter, a method for developing a Pending Loads category and incorporating it into distribution planning. The advice letter shall describe how the information presented at the workshop has influenced the proposal and should include the workshop report as an appendix. The proposals shall define types of information that shall be considered in the Pending Loads category. The proposals shall define the general criteria or reasoning applied to each Pending Load category to determine if the information will result in a Pending Load and if so, the size of the load. The proposals shall discuss the risk of pending loads that do not materialize, and how to mitigate this risk.

Nothing in this proposal prevents utilities from immediately implementing a pending loads category in their distribution planning while this process is underway. Utilities should not be overly prescriptive or formulaic in defining their processes to determine pending loads to allow flexibility within distribution planning. To provide for additional flexibility and allow for continued improvement in the future use of the Pending Load category, utilities may also submit a Tier 1 Advice Letter once per year to inform the Commission of methodological or procedural changes to the Pending Loads category or how it is used within distribution planning. This Tier 1 AL should explain how any changes improve the process.

The Pending Loads category should be, at minimum, informed by existing coordination efforts, planning programs, and an aggregation of publicly available information, such as the following:

Existing coordination and customer outreach efforts

Utilities, as directed by Resolution E-5247, must meet with EVSPs to discuss development plans. Pursuant to AB 50, utilities must meet with local government representatives and county staff to discuss "planned capacity upgrades, projected local demand, local development plans," among other things. Additionally, customers who are required to electrify under CARB regulations that contact utilities early with their development plans should be considered in the pending loads category.

Planning programs

Other state agency group planning efforts. Local and regional planning entities have access to electrification planning tools that can be used to anticipate the amount of capacity their communities will need. The National Renewable Energy Laboratory (NREL) has developed the Electric Vehicle Infrastructure – Projection Tool (EVI-Pro) to estimate how much EV charging infrastructure is needed in a designated area to meet a given demand.[68] The IOUs should seek

[68] Alternative Fuels Data Center: Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite (energy.gov)

information from local and regional entities who use these tools to ensure they communicate the outcomes to their utility.

Public Information and other programs

There are other miscellaneous sources of information that can be leveraged to inform pending loads, including approved grants and state or federal funding programs. For example, the California Infrastructure and Economic Development Bank (IBank) is working with a group of state agencies to prepare an application for the Environmental Protection Agency's *Solar for All* program to install solar and storage in disadvantaged communities. These applications detail the census tracts the grant funding will be allocated to and the number of people it will serve. The information in the completed application can be relayed to utilities to inform the creation of timelines for grid developments needed to implement the project before the actual requests for service are issued to the utilities.

Rationale:

- The two components that currently guide utilities in disaggregating forecasted load to specific location on the grid are known loads and economic modelling. Known load data is based on existing energization requests from customers that have gone through utility review, while economic modelling uses general trends and economic and demographic characteristics to estimate load growth across the whole utility territory. Known loads provide the most certainty in distribution planning but are only complete in the very near-term; known loads are complete in the first year of the forecast but drop off significantly as early as years 2 and 3. This drop in known loads occurs because customers often do not submit service requests to utilities multiple years ahead of their need.
- The utilities should develop an intermediate category, i.e. Pending Loads, which is based on combining and statistically analyzing various information sources to estimate future load growth at specific locations before customers officially apply for energization. These Pending Loads would have a level of certainty less than known loads, but greater than broad-based econometric disaggregation. Pending loads draws from both of these other categories; it is both a response to early engagement from customers and proactive forecasting to identify least-regrets upgrades. Pending loads can provide a greater level of certainty to the forecast and fill the gap between applications for service at specific locations that are underway and trend-based dispersed load growth across the system.
- The pending loads category is directly responsive to new legislation including multiple directives in SB 410 and AB 50 (see Table 6.)

Additional Questions for Stakeholder Consideration:

1. How can 'pending loads' as a category be derisked to prevent investing in upgrades for loads that do not materialize?

2. Should the Commission emphasize that the IOUs only develop pending loads in 'least regrets' areas or using 'least regrets' methods?
3. Should pending loads be implemented in stages? If so, how? For example, limiting early implementation to specific geographic areas, load types, or only in forecast years 3-6.
4. Should pending loads be allowed to exceed the annual IEPR load growth cap or should the Commission require it to be "within" the growth cap?

Tentative Timeline: Next DPP Cycle

3.2.8. Utilities to Develop Prioritization Methods Beyond the Current Consideration of Project Need Dates

Related Issues and Goals: Issue 3.1.11: Project Prioritization, Key Goal 1, Key Goal 2, Key Goal 3

Related Legislation: n/a

Party Comments: SCE and SDG&E generally noted that consideration of project prioritization was not necessary, as they aim to complete all projects by the time they are needed.[69,70]

Other parties requested an expanded explanation of utility prioritization methods.[71,72]

Commission Action: The IOUs should submit high-level plans detailing how they currently are, or how they would, if necessary, prioritize between projects outside of the current consideration of project need date. These plans should be submitted and can be updated via Tier 1 Advice Letter, and should discuss:

- The potential basis for or driver of the need(s) for prioritization.
- The possibility of prioritizing long lead-time capacity projects to mitigate difficulties with project execution.
- How their plans take equity into consideration.
- Various potential metrics for prioritization, including, at minimum, the following:
    - Grid need occurs in all forecast scenarios (low, medium, and high as described in 3.2.5)

[69] SCE's Supplemental Responses and Comments to Assigned Commissioner's Amended Scoping Memo and Ruling, Appendix A at 9
[70] SDG&E's Response to Assigned Commissioner's Amended Scoping Memo and Ruling – Questions for Supplemental Utility Response at 4
[71] Reply Comments of Small Business Utility Advocates to Utility Responses to Amended Scoping Memo Appendix A at 6
[72] Reply Comments of Joint CCAs Replying to Investor Owned Utilities' Responses [to Amended Scoping Memo Appendix A] at 5

- Likelihood that grid need will occur
- Number of grid needs addressed
- Timing, frequency, and duration of grid need
- Types of grid needs addressed by the planned investment
- Whether the grid needs are fully addressed by the planned investment
- Cause of the grid need, for example organic load growth versus energization request
- Number of customers served
- Types of customers served
- Disadvantaged community status of the service area
- Grid need related to state policy goals or plans (e.g., customer efforts to comply with regulation such as ACCII, ACF, ACT, etc.)

In addition, the IOUs must include in their annual DDOR reports or any successor filings a description of the extent to which these prioritization plans are being used in actual distribution planning and execution, including the number of projects to which they have been applied and their ranking relative to other prioritization metrics.

Rationale:

- IOUs should be prepared to prioritize between projects equitably and reasonably to the extent this prioritization is useful or necessary, as further described in Section 3.1.11.
- IOUs should inform the Commission and stakeholders when they choose to prioritize between projects beyond the consideration of project need date, and it is reasonable to include this information in the already existing venue of the DDOR reports.

Tentative Timeline: Advice Letter in 2024

3.2.9. Utilities to Consider Distribution Planning Results When Doing Other Distribution Work (Integrated Planning)

Related Issues and Goals: Issue 3.1.4: Coordination and Planning, Key Goal 2.

Related Legislation: n/a

Party Comments: PG&E and SCE have already identified integrated planning as a goal. PG&E, in their response to the ALJ Ruling Seeking Additional Information on the Distribution Planning Process[73], indicated that they plan to "prioritize across multiple objectives" and to "seek opportunities to address multiple grid needs with a single solution."[74]

[73] ALJ's Ruling Seeking Additional Information from Investor-Owned Utilities on their Distribution Planning Process
[74] PG&E Answers to ALJ's Ruling Seeking Additional Information on the Distribution Planning Process at 16

Similarly, SCE reported their intent to develop an integrated planning process that brings together "system hardening for wildfire mitigation, infrastructure replacement programs, climate adaptation driven asset replacements, distribution transformer maintenance, and distribution pole programs" to "holistically consider multiple drivers for infrastructure upgrades and propose optimal solutions to mitigate grid needs and least regret investments."[75] The proposal considered here does not have the wide scope of these current projects, but should correspond to them.

Commission Action: Direct the utilities to consider, in their other distribution workstreams, upgrading the capacity of any primary distribution infrastructure to avoid the need for future distribution capacity upgrades.

The utilities shall propose, via a Tier 2 Advice Letter, a method for referring to the results of their DPP when designing projects in other distribution workstreams. In this Advice Letter, utilities should balance (1) the increased project costs from the increased sizing of any related assets, with (2) the risk-adjusted benefit from avoiding future projects to upgrade grid capacity. For example, utilities should increase the capacity of a current project if:

$$\text{(Increased Cost for Current Project)}$$

$$\textit{iiii lllliiii tthaaaa}$$

$$\text{(Probability of Future Grid Need)}\ \textit{mmmmllttiimmllllmm bbbb}$$

$$\text{(Cost of Potential Distribution Capacity Project, Adjusted via Discount Rate)}$$

The utilities proposal should allow for future development of the distribution planning process and should not become a barrier to future changes in that process. In their Advice Letter, utilities should address the following questions:

- How does the proposed method maintain the flexibility of the distribution planning process, and allow for that process to develop over time?
- How does the proposed method estimate the increased costs for current projects, and how can this estimate change or improve over time?
- How does the proposed method adjust for risk when considering potential future capacity projects, and how can this adjustment change or improve over time?
- How does the proposed method estimate cost of future distribution capacity projects, and how can this estimate change or improve over time?

Once approved, any changes to the method should be made by Tier 1 Advice Letter if the utility argues that (1) they will improve the method's accuracy and (2) in the majority of cases, the decision whether or not to increase the capacity of distribution infrastructure remains the same.

[75] SCE Comments to ALJ's Ruling Seeking Additional Information on the Distribution Planning Process at 3

Rationale:

- During a time of growing energy needs, it may not be appropriate to build assets to meet current demand without considering future growth. The results from forecasting and disaggregation in the distribution planning process can be leveraged, where reasonable, to determine the future capacity needs of assets that are being built or replaced. Therefore, distribution assets being replaced or built through other workstreams, for example wildfire work or repair work, should be sized appropriately to serve customers throughout their expected life. This makes sense from a cost perspective: increasing the capacity of a conductor for a project has a relatively small effect on overall project cost, especially when compared to the benefit of avoiding a potential future distribution capacity project. For example, a line section being undergrounded should be planned and constructed with enough line capacity to meet all grid needs identified in distribution planning over the planning horizon (i.e. 10 years).
- Utilities are expected to improve their distribution planning process in the future—based on this staff proposal, future work in this proceeding, new technologies and methods, and their own initiative. This proposal should not hinder the development of the DPP, and utilities should be able to quickly integrate improved results from the DPP, or changes to that process, into the method proposed here.

Timeline: Advice Letter in Q1 2025.

3.2.10. Utilities to Develop Bridging Strategies to Better Accommodate Energization Requests that Trigger Distribution Capacity Work

Related Issues and Goals: Issue 3.1.6: Delays and Long Energization Timelines, Key Goal 1

Related Legislation: SB 410: PUC Section 936(a)(2)

Party Comments: Both SCE and PG&E mentioned that they currently have processes to respond to energization requests that require a distribution upgrade in the current, ongoing DPP cycle, and that they are considering strategies to energize customer load before needed capacity projects are completed.[76,77]

[76] SCE's Supplemental Responses and Comments to Assigned Commissioner's Amended Scoping Memo and Ruling, Appendix A at 6

[77] Responses to Amended Scoping Memo Appendix A by PG&E at 5

Commission Action: Direct the IOUs to file a plan via Compliance Filing for deploying various strategies to better accommodate energization requests that trigger upstream distribution capacity work. This plan should discuss, at minimum:

- Improvements to utilities reactive processes when a new energization request comes in that requires an upgrade to distribution capacity.
- Temporary constraints on the power these customers are allowed to draw, e.g., load management, until a distribution capacity project is complete, with the goal of only constraining customers during times of peak infrastructure use.
- Acquiring and deploying mobile DERs capable of managing and preventing grid deviations while a distribution capacity project is underway.

The IOUs shall include a section in each DDOR or successor filing that describes the progress made in implementing these various strategies.

Rationale:

- Customers are likely to continue requesting energization on short notice and utilities cannot proactively plan for distribution capacity in a way that always prevents these requests from requiring upstream distribution capacity upgrades. Given this situation, utilities should improve how they handle energization requests that are pushed back due to needed distribution capacity work.
- In many cases, there is only a risk of exceeding a capacity limit on a circuit or substation bank during peak summer hours. If customers with flexible loads can reliably reduce their loads during these key times to avoid a grid deviation, they should be able to energize rapidly. Once the related distribution capacity project is complete, these limits on customer loading will be removed.
- For some grid issues, the temporary placement of a DER may be able to mitigate the grid need while a more permanent solution is being executed. For example, a temporary battery connected at a substation may be able to reduce peak loading and resolve capacity constraints while a substation bank upgrade is planned and executed. This solution will be case dependent, as interconnecting a DER may not be feasible due to space constraints, safety issues, or other factors.

Timeline: Compliance Filing in 2024.

3.2.11. Utilities to Prepare a Load Flexibility DPP Assessment

Related Issues and Goals: Issue 3.1.8: Grid Modernization, Key Goal 1

Related Legislation: n/a

Party Comments: Parties generally noted that load flexibility could be an important resource with the possibility of reducing needed upgrades.[78,79,80]

The IOUs generally noted that load flexibility is not currently developed enough to be a standard alternative to distribution capacity.[81,82]

Background: In the realm of transportation electrification, load management and flexible loads can play crucial roles in optimizing energy usage and controlling distribution upgrade costs.

Load Management: Load management involves strategies to control or adjust the electricity demand on the grid. In transportation electrification, this typically refers to managing the charging of electric vehicles (EVs). Load management techniques aim to distribute and schedule the charging of EVs efficiently to avoid grid strain during peak times. This might involve implementing time-of-use pricing, smart charging stations, or demand response programs that incentivize users to charge their EVs during off-peak hours when electricity demand is lower.

Flexible Loads: Flexible loads refer to devices or systems that can adjust their power consumption in response to external signals such as price fluctuations, grid conditions, or specific commands. In the context of transportation electrification, EVs can serve as flexible loads. They can adjust their charging patterns based on signals from the grid operator or energy management systems, allowing them to charge when renewable energy sources are abundant, electricity prices are lower, or when the grid has excess capacity.

In summary, load management focuses on the overall strategy and techniques to optimize the electricity demand, often involving scheduling and control mechanisms. Meanwhile, flexible loads pertain to the capability of specific devices, like EVs, to adapt their power consumption patterns in response to external factors for better grid integration and efficiency. Both concepts are interconnected and crucial for the successful integration of electric transportation into the broader energy ecosystem.

Commission Action: Direct IOUs to submit via Tier 2 Advice Letter a Flexible Load DPP Assessment that quantifies the potential for flexible load strategies to reduce future distribution costs at the primary and secondary distribution level. This assessment is not about developing detailed flexible load strategies, rates, policies and programs which

[78] Center for Biological Diversity, The Climate Center, 350 Bay Area, Vote Solar, Sierra Club and The Clean Coalition Opening Comments on ALJ's Ruling Directing Responses to Questions on Track 1 Phase 1 at 31
[79] Comments of Microgrid Resources Coalition on the ALJ's Ruling Directing Responses to Questions on Track 1 Phase 1 at 4
[80] Clean Coalition Reply Comments In Response to ALJ's Ruling Directing Responses to Questions of Track 1 Phase 1 at 11
[81] PG&E Responses to ALJ's Ruling on Track 1 Phase 1 Questions at 13
[82] SCE Responses to ALJ's Ruling on Track 1 Phase 1 Questions at 13

are beyond the scope of the High DER OIR. Rather the intent of the assessment is to examine how future load shapes resulting from a range of flexible load strategies could impact distribution planning such as controlling distribution upgrade costs. The assessment would also address how the DPP process can incorporate results of flexible load strategies into the planning process. Many of the flexible load strategies, rates, policies and programs are being developed in related proceedings including: Demand Flexibility and Transportation Electrification.

Utilities shall conduct load shape analysis to determine the distribution system level benefit of demand flexibility, including a quantification of avoided costs. The IOUs shall publish their load flexibility inputs and assumptions along with justification for their decisions in Q4 2024 for public comment. IOUs shall consider the feedback and file the Flexible Load DPP Assessment in Q2 2025. One example assumption that should be tested is the scenario where utilities control the dispatch of flexible loads.

The goal of the assessment is to better enable utilities to strategically incorporate load management and load flexibility techniques into their distribution planning and provide transparency and an opportunity for stakeholder input on how utilities are planning to accomplish this goal. Results of the assessment could inform current efforts in related proceedings developing the load flexibility strategies, rates, policies and programs.

Rationale:

- Incoming electrification load may apply for energization faster than utilities can upgrade their systems. In the realm of transportation electrification, load management and flexible loads can play crucial roles in optimizing energy usage and controlling distribution upgrade costs.
- Given the magnitude of electrification-related load expected, flexible loads are going to be a resource of significant scale in the medium- to long-term with the potential to mitigate substantial distribution infrastructure cost.

Timeline: Advice Letter in 2025

3.2.12. Recommend More Flexible Inputs for Utilities to Request Distribution Capacity Costs in the GRC

Related Issues and Goals: Issue 3.1.7: Cost Recovery, Key Goal 2

Related Legislation: SB 410: PUC Section 937(d)

Party Comments: SCE noted that they submitted an additional analysis to their GRC (the TEGR) in order to produce more reliable funding forecasts.[83] Utilities generally noted

[83] SCE’s Response to ALJ’s Ruling Directing Responses to Questions on Track 1 Phase 1at 21

that making outdated DPP results the key input to GRC forecasts can lead to funding issues.[84,85]

The Small Business Utility Advocates comment that it is necessary to improve the GRC process so necessary costs can be approved through the GRC process where funding decisions are made.[86]

Commission Action: Under current regulations, utilities can add content to their GRC testimony due to emergent needs or changing forecasts, but this is discouraged. The Commission should rescind paragraphs (h) and (i) of OP 2 from D.18-02-004, and encourage utilities to conduct and submit additional supplemental analysis on grid needs and forecasts to mitigate the process lag between the IEPR, DPP, and GRC, especially when there are major changes in state electrification policy. Supplemental analysis should make clear any discrepancy between the forecast used for GRC request and the IEPR.

Rationale:

- Decision D.18-02-004 that established the DIDF included the following orders:

    > *h. The information each IOU presents in its GRC testimony shall be consistent with that which the IOU presents in that year's GNA and DDOR reports, while affirming the IOU's ability to update any aspect of its GRC testimony due to emergent needs or changing forecasts that arise following that year's GNA and DDOR filings. The IOUs must explain any discrepancies between the GNA and DDOR reports and GRC testimony within the GRC testimony.*
    >
    > *i. The Commission orders that the GNA and DDOR filed the year after a GRC filing year is inadmissible in the evidentiary record of that GRC proceeding, and may not be used to update the underpinning assumptions of GRC testimony that was filed the previous year.*

    These paragraphs unnecessarily restrict the information utilities can use in their GRCs, potentially contributing to funding issues for distribution capacity work. The Commission should acknowledge that large changes in state electrification policy certainly qualify as both emergent needs and changing forecasts, and that utilities' GRC testimonies should be flexible in responding to these potential changes. The Commission supports utilizing credible third-party studies as evidence. Any GRC requests and related analysis will continue to be scrutinized by the GRC review process.

Tentative Timeline: Next GRC

[84] SDG&E Response to ALJ Ruling Seeking Additional Information from Investor-Owned Utilities on their Distribution Planning Process at 9

[85] PG&E Answers to ALJ Ruling Seeking Additional Information on the Distribution Planning Process at 25

[86] Reply Comments of Small Business Utility Advocates to Utility Responses to Amended Scoping Memo Appendix A at 3

3.2.13. Utilities to Submit Community Engagement Plans that Specifically Address Equity

Related Issues and Goals: Issue 3.3.9: Local Engagement, Key Goal 1; Issue 3.1.10: Equity, Key Goal 1

Related Legislation: SB 410: PUC Section 936(a)(2); AB 50: PUC Sections 933.5(c)(2) and 933.5(c)(3)

Party Comments: The IOUs provided mixed comments, with SCE supporting the development of an engagement plan[87] and SDG&E arguing that local and community engagement should be streamlined across proceedings rather than handled individually in each proceeding.[88] Joint CCAs supported engagement but expressed skepticism about the IOUs conducting outreach directly.[89]

Commission Action: Require Utilities to submit a Community Engagement Plan (CEP) specific to their service area that includes plans to comply with the requirements for annual meetings and data sharing in AB 50. Require that the engagement plans address how community feedback will be incorporated into IOUs' DPP and specifically address Tribal community needs, Environmental and Social Justice equity considerations, and Disadvantaged Community needs. The CEPs may be created in coordination with other engagement efforts by the utilities. The CEPs shall be filed on the High DER Proceeding record.

The CEPs shall include, at minimum, a description of the IOUs current efforts and future plans to:

- Conduct regular outreach to local governments, Tribal governments, and communities to engage in two-way dialogue.
- Coordinate with and incorporate findings from existing engagement activities, such as those mentioned in 3.1.9.
- Ensure language accessibility and disability accessibility in engagement.
- Promote energy literacy and understanding of the distribution planning process, including the potential for upstream distribution projects to impact energization timelines.
- Provide transparency into the distribution planning process.
- Comply with the requirements of PUC Sections 933.5(c)(2) and 933.5(c)(3), as mandated by AB 50.

The CEPs shall also cover the following topics:

- How community feedback will be addressed in distribution planning through Pending Loads or other avenues.

[87] SCE Comments to ALJ's Ruling Directing Responses to Acquisitions on Track 1 Phase 1 at 5
[88] SDG&E Comments to ALJ's Ruling Directing Responses to Acquisitions on Track 1 Phase 1 at 2
[89] Opening Comments of Joint CCAs Responding to Questions on Track 1 Phase 1 at 3

- How information from local governments, planning agencies, and Tribal governments relating to potential new local energy needs will inform distribution planning.

Rationale:

- A CEP allows greater visibility into Utilities' distribution planning while directly addressing concerns raised by community leaders and representatives, including resiliency, economic development, workforce expansion, and energy affordability. This plan aligns with the core principle of inclusivity, transparency, and partnership that stakeholders have emphasized. The CEP not only ensures that the unique needs and perspectives of communities are considered but does so in a manner that does not provide undue burden to Utilities or the Commission. The CPUC endorses the Utilities' position that engaging communities directly, rather than through third-party consultants, improves efficiency, reduces costs, and allows for improved relationships between IOUs and communities.
- The proposed CEP may be designed to ensure a proactive and continuous engagement approach throughout this proceeding. By integrating transparent metrics and regular reporting on how community feedback is incorporated into the utility Distribution Planning Process, the proposed CEP sets the stage for a more responsive planning process. This plan underscores a shift away from reactive and application-based engagement to a system that seeks and prioritizes community input proactively, thus ensuring that community needs can inform both investment and procurement decisions.
- The CEP must specifically address the unique needs of tribal communities. Tribal communities have experienced historic and ongoing disenfranchisement. California Tribes represent unique utility customers as they are often located at the end of distribution lines and/or in remote and rugged areas, subject to frequent and lengthy outages, and are subject to burdensome service delays. They have been left behind in building the modern distribution system but cannot be left behind as California seeks to plan and upgrade the grid for electrification. California Tribes are sovereign entities, many of which are seeking energy independence through tribal-owned microgrids and DER projects. California Tribes must be engaged explicitly in the distribution planning process in regular dialogue that informs Tribes about utility plans and promotes creative thinking about institutional and economic challenges facing tribal energy goals.

Tentative Timeline: 2025

3.3. From DIDF to Transparency in Distribution Planning

3.3.1. The History of the DIDF

With Decision 18-02-004 in 2018, the Commission established the Distribution Investment Deferral Framework (DIDF) directing the IOUs to attempt to defer traditional utility investments through DERs. The goal of DIDF was to identify and select relatively low-cost opportunities for DERs to defer traditional capital investments considered by the IOUs, and for the IOUs to pursue an open market solicitation for DER solutions. The DIDF process has focused on non-wired alternatives to specific distribution investments at specific grid locations. The Commission adopted various metrics for identifying and selecting these opportunities, including metrics for cost-effectiveness, forecast certainty, and market assessment. The DIDF process also provided information on the actual cost of distribution system upgrades and the process of distribution planning to the Commission and the wider public. The Commission ordered Utilities to meet with the Distribution Planning Advisory Group (DPAG), a stakeholder group consisting of IOUs, Commission technical staff, an Independent Professional Engineer technical consultant, non-market participants, consumer advocates, and DER market participants. The Commission further ordered that Utilities provide reports detailing their distribution planning, the GNA and the DDOR.

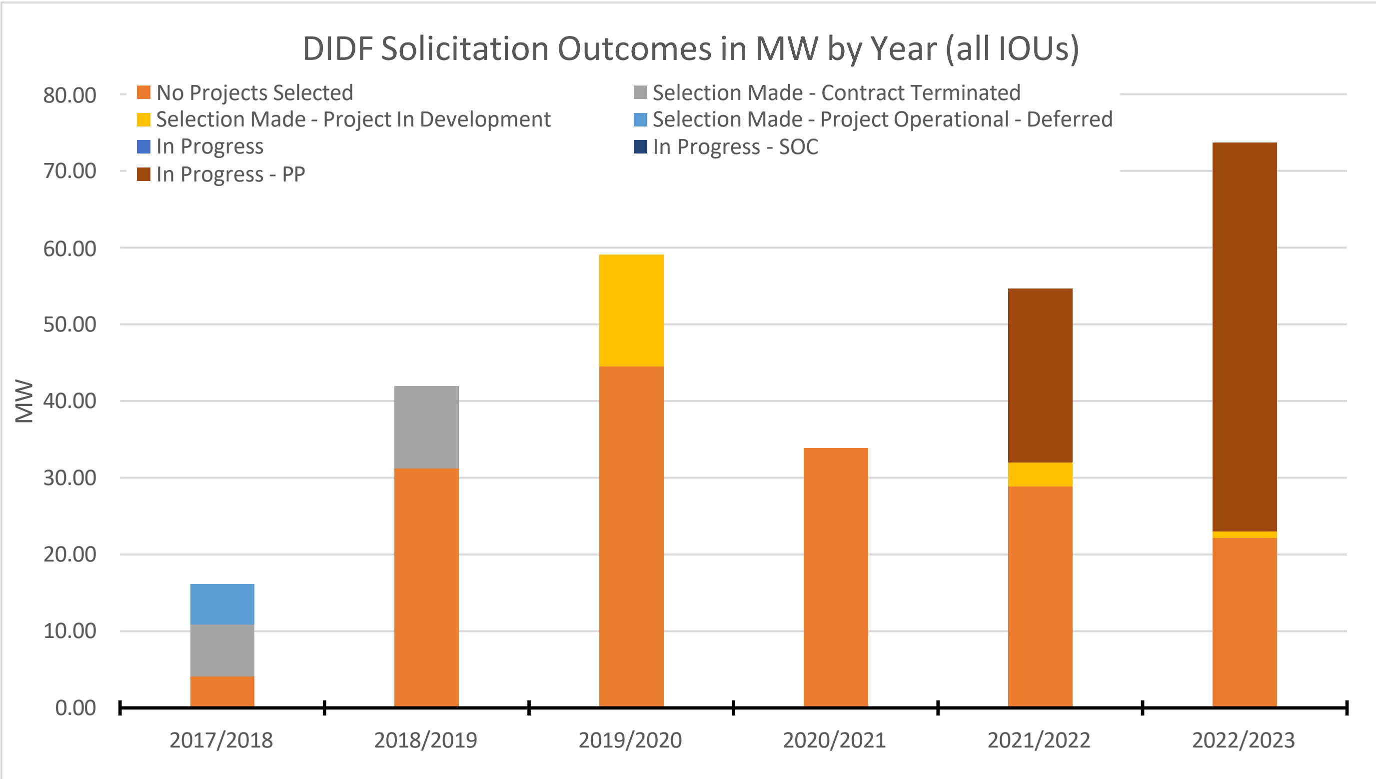
In its current form, the DIDF begins with the utilities proposing selected IEPR forecast scenarios to apply to the next DPP cycle. After a workshop with the Distribution Forecasting Working Group, where the utilities present and justify their scenario selection, there is a round of comments and reply comments, and the selection subsequently proceeds through informal energy division approval. Utilities submit their bi-annual DIDF Procurement Status Report to Energy Division, the Independent Professional Engineers (IPE), and the Independent Evaluators (IE). Utilities launch the prescreening period for the Partnership Pilot solicitation mechanisms to allow developers to request approval to access BTM deferral project opportunities. The IEs submit their Post-Procurement Utility Comparison Report. The utilities file their GNA and DDOR for the current cycle. The IPE submits their plans for the cycle and their Preliminary Analysis of GNA/DDOR Data Adequacy reports. Utilities launch their Request for Offer (RFO) solicitations, and their Standard Offer Contract (SOC) solicitations before the SOC pilot was off-ramped. All parties convened for the Distribution Planning Advisor Group workshop week, where each IOU presents their GNA and DDOR reports, as well as details for the identified deferral opportunities, and the IPE presents their analysis thus far, for half or full day workshops. Following the DPAG week, participants have the chance to ask questions to the DPAG workshop presenters and follow-up workshops, meetings, and/or correspondences take place. The IPE submits the DPAG Report on the utilities work for the current cycle. Utilities file two Tier 2 Advice Letters, the first to launch their selected Partnership Pilot projects, and the second for approval to not launch the unselected projects through any solicitation mechanism. These Advice Letters are reviewed and approved or resolved by Energy Division, taking participant protests into consideration, if applicable. Following the Advice Letters, utilities launch their Partnership Pilots and a second round of RFO, and previously SOC, projects. The IE sends out the Partnership Pilot Response Survey to developers and aggregators to solicit feedback on the process for future reform. Utilities present their project shortlists to the Procurement Review Group of the previous RFO solicitation, then subsequently submit an information only Advice Letter notification of executed

RFO, and previously SOC, projects. Utilities update their Partnership Pilot website with a notice of availability of procurement tranches for aggregators to bid for. The utilities submit their Annual Partnership Pilot Evaluation Reports, the IE submits the DIDF RFO/SOC Reports and their Annual Partnership Pilot Evaluation Report, and the IPE submits the Post-DPAG Report. There is a round of comments and replies on reforms to DIDF and the solicitation pilots, and the cycle ends with a reform ruling, informed by comments, that makes incremental changes to the DIDF with the aim of improving the deferral process and sets the schedule for the next cycle. All of the work done by the IE and IPE is coordinated and directed by Energy Division and extensive review of the 13 submitted work products, 6 workshops, 3 comment and reply comment periods, and 3 rounds of Advice Letters are considered throughout.

Since its inception DIDF has undergone annual reform through rulings in proceeding R.14-10-003 in attempts to make it more successful.[90] On February 11, 2021, the Integrated Distributed Energy Resources (IDER) Decision 21-02-006 made further reforms to the solicitation methods used in the DIDF, including introducing the Partnership Pilot and Standard Offer Contract (SOC) Pilot to promote alternative solicitation methods to the standard RFP process and more diverse solutions including behind-the-meter DERs. Despite repeated reform, DIDF has not led to as many deferral projects as hoped, and as a result the SOC Pilot was shut down in May of 2023. As seen in Figure 3-19, no projects were selected for the majority of deferral opportunities, and of the few selected projects even fewer are currently operating successfully.

Figure 3-19: DIDF Solicitations Outcomes in MW by Year for all IOUs

[90] See the May 7, 2019 Ruling Modifying the Distribution Investment Deferral Framework Process; the April 13, 2020 Ruling Modifying the Distribution Investment Deferral Framework Process; the May 11, 2020 Ruling Modifying the Distribution Investment Deferral Framework-Filing and Process Requirements; and the June 21, 2021 Ruling on Recommended Reforms for the Distribution Investment Deferral Framework Process



Source: Independent Evaluator Post-Procurement Utility Comparison Report, Supporting DIDF Tracking Spreadsheet 2022-2023

This current rulemaking has again taken up DIDF reform, largely in response to a lack of successful deferral outcomes despite many attempts at reforms. The IOUs voiced concerns with the DIDF Reform process, claiming that repeated reform both slowed IOUs' ability to operate and added regulatory burden by expanding the data IOUs are required to provide. In its current form, the DIDF has not done well in deferring traditional wires investments. Although there may still be issues with the DIDF structure itself, consistent lackluster results indicate that, in general, it can be difficult and expensive to defer these investments through DERs. Even when they are cost-effective, non-wires alternatives can fail for many reasons including changing project needs and locations, barriers to DER deployment such as interconnection delays, uncertainty in the contracting process, and developer failure. While proving somewhat ineffective at increasing DER implementation, the DIDF process *has* provided significant benefits, specifically by ensuring transparency into IOU distribution planning and access to data for CPUC and the public.

3.3.2. New Goal for DIDF: Reporting on Distribution Planning Rather than Deferring Distribution Infrastructure Investments

In order to meet the state's electrification goals, which will lead to a significant increase in electrical demand over the coming decades, the IOUs will have to build additional distribution capacity. In this context, continued focus on deferring distribution infrastructure projects, especially when previous attempts have not been successful and when the current framework of point-specific deferral projects aims at a single locations, is potentially counterproductive.

Staff's finds that stakeholder, Commission, and IOU efforts should be directed to issues other than the DIDF process and DIDF reform. To facilitate this shift in focus, Staff preliminarily recommends that the DIDF should be pared down and directed toward facilitating (1) transparency in distribution planning and (2) the monitoring of distribution planning improvements and developments by the Commission and by stakeholders more broadly. Non-point specific deferral opportunities still exist such as load flexibility.

Although the DIDF will be taken up in more detail in Track 1 Phase 2 of this proceeding, Staff provide options to take sooner action to refocus the DIDF process on transparency and monitoring, rather than point-specific distribution infrastructure deferral.

3.3.3. Deprioritize DIDF to Free Up Stakeholder Time

Party Comments:

- IOUs are in favor of pausing the DIDF reform and DPAG for the 2024 and 2025 cycles and considering wholistic reform in Track 1 Phase 2.[91] PG&E suggests that the High DER Proceeding focus on accelerating capacity expansion because deferral is counterproductive in an era of load growth.
- The Public Advocates Office is in favor of pausing DIDF reform but continuing DPAG because it is a useful transparency window into the DPP and an opportunity to ask questions to IOU SMEs. [92]
- Some parties comment on pausing the DIDF and DPAG or ending the DIDF entirely,[93] while other parties make suggestions for incremental[94] or wholistic[95] changes in DIDF.

Commission Action Option 1 (Status Quo): Continue with DIDF in its current form until the Track 1 Phase 2 DIDF reevaluation.

Rationale: Although wholistic reform of the DIDF process is widely supported, the current process still provides valuable information to the public. Some stakeholders continue to be in favor of making incremental improvements to the DIDF to increase the amount of DER deferrals, implement more cost-effective solutions, and use DERs to as bridging solutions until traditional upgrades can be built. The scope of DIDF reform can be modified as needed during this period. It could only include minor changes necessary to maintain the DIDF or continue to implement incremental changes to improve the solicitation outcomes. This will uphold what staff sees as the main strength of the framework: transparency. While staff finds that the DIDF should be fully reevaluated, it can also continue to provide value while that process is underway.

[91] Responses by PG&E, SCE, and SDG&E to ALJ's Ruling Directing Responses to Questions on Track 1 Phase 1
[92] Comments of the Public Advocates Office on ALJ's Ruling Directing Responses to Questions on Track 1 Phase 1 at 17
[93] Comments of the Coalition of Utility Employees Track 1 Phase 1 Questions at 17
[94] Clean Coalition Comments In Response to ALJ's Ruling Directing Responses to Questions on Track 1 Phase 1 at 23
[95] Comments Of Microgrid Resources Coalition On The Administrative Law Judge's Ruling Directing Responses To Questions On Track 1 Phase 1 at 4

Commission Action Option 2: Continue with DIDF in its current form until the Track 1 Phase 2 DIDF reevaluation *but cancel all DIDF reform processes*.

Rationale: For the reasons in option 1, the DIDF continues to be a useful tool for transparency. Until it can be fully reevaluated later in this proceeding, stakeholder time devoted to DIDF should be reduced by cancelling all reform processes.

Commission Action Option 3: Focus DIDF reform on facilitating (1) transparency in distribution planning and (2) the monitoring of distribution planning improvements and developments by the Commission and by stakeholders more broadly. Shift focus away from deferral by reframing (and renaming) the DDOR as the Distribution Upgrade Project Report (DUPR) and cancelling the DPAG workshops. Change the name DIDF to remove the word "deferral" and ascribe a new name that better describes the new scope.

Rationale: Until there is time to fully reevaluate the DIDF later in this proceeding, the Commission could pause the deferral-focused DIDF incremental reforms that have not meaningfully increased the number of deferrals. Instead, a similar process could continue reporting on grid needs and associated solutions but remove a number of steps that are not serving distribution planning or execution. This change would begin the shift away from DER deferral and refocus on increased transparency into distribution planning, solution identification, and execution. Therefore, the DDOR will be reframed as the Distribution Upgrade Project Report (DUPR) and the sections that identify and select specific projects for DER deferral would be cut. The DUPR would explain the process for determining the chosen grid need solution and ID and report all the identified projects. This scaled-down version of the DIDF would also cancel the DPAG meetings, as the utilities would not continue to identify and present deferral candidates for procurement. This would serve as an intermediate step toward wholistic DIDF reform while preserving the most valuable outcomes of the DIDF.

Tentative Timeline for all options: 2024 DIDF Cycle, beginning with the August 15th GNA/DUPR filing.

3.3.4. Include Metrics to Evaluate Equity in Utility Distribution Plan Reporting

Related Issues and Goals: Issue 3.1.10: Equity, Key Goal 1

Commission Action: Instruct the IOUs to include the following data in their GNA and DDOR filings, or any successor filings, about each relevant grid need or distribution project:

- Percentage of customers served by the relevant equipment/facility that are currently in the CARE/FERA programs.
- The CalEnviroScreen 4.0, or the most recent update at the time of filing, percentile for the area served by the relevant equipment/facility.

- Whether the equipment/facility serves a DAC.

This information does not need to be included for facilities and/or equipment that does not clearly serve a set of customers, i.e. a new switch, but must be included for facilities and/or equipment that clearly serves a set of customers, including but not limited to circuit segments, circuits, substation banks, and substations.

Rationale:

- Data on equity in distribution planning and execution will help the Commission and stakeholders evaluate equity in the distribution planning process. Reporting this information over time will help track how equitably distribution grid upgrades are distributed.

Tentative Timeline: 2025 DPP Cycle

3.3.5. Include Metrics to Track Project Execution in Utility Distribution Plan Reporting

Related Issues and Goals: Issue 3.1.6: Delays and Long Energization Timelines, Key Goal 2

Commission Action: Instruct the IOUs to include data in their DDOR filings, or any successor filings, detailing all ongoing distribution capacity projects and all projects finished within the last three years. This data should include:

- DDOR Project ID from all past DDOR reports.
- Year that the project was first identified within distribution planning.
- Associated Grid Needs identified within distribution planning.
- A list of any known loads associated with the project.
- Original expected operating date from first identification within distribution planning.
- Current project status.
- Current expected or actual operating date.
- Delta between original expected and current expected operating date, if applicable.
- Delta between original expected and actual operating date, if applicable.
- Related Substation and Circuit, if applicable.
- A ‘Yes’ or ‘No’ response to whether the related pieces of infrastructure are currently included or have been included in the past 5 years in any other distribution workstream, for example included within a wildfire hardening project or tagged for asset repair. For every ‘Yes’ response, include a simple categorization of the other workstreams where related infrastructure has been included, e.g. ‘Asset Repair’ or ‘Wildfire.’
- For completed projects, a ‘Yes’ or ‘No’ response to whether historical loading from the most recent planning cycle confirms the need for the project (For example, whether the most recent historical loading on a circuit, as adjusted to 1 in 10 for use

in distribution planning, exceeds the capacity of the old infrastructure). This should look at adjusted historical loading data and not future forecasts.

- For completed projects, a 'Yes' or 'No' response to whether forecast loading for the next 5 years in the most recent planning cycle confirms the need for the project (For example, whether the most recent forecast for circuit loading over the next five years, as used in distribution planning, exceeds the capacity of the old infrastructure).
- For completed projects, cost of the project and expense account where the cost is recorded.

In addition, each DDOR report should include a section on current total spending on distribution capacity, including substation work, in comparison to approved funding from the most recent GRC. This should include actual spending in the previous year, actual spending in the current year to date, and approved funding from the most recent GRC for equivalent time periods.

Rationale:

- The Commission and stakeholders should have transparency into the execution of distribution capacity projects in addition to the distribution planning process.
- The Commission should require utilities to collect and make public some simple metrics on the efficacy of its distribution planning, including confirming whether each completed distribution capacity projects corresponds to actual and/or forecasted changes in load.
- In PG&E territory, one factor contributing to current distribution capacity project delays and related lengthy energization timelines is that PG&E redirected funding from distribution capacity work to wildfire-related work in 2018 and 2019. In the future, the IOUs should publicly report when they redirect significant funding into or out of distribution capacity work.

Tentative Timeline: 2025 DPP Cycle

3.3.6. Up-To-Date Utility Known Load Project Tracking and Reporting with the CEC.

Related Issues and Goals: Issue 3.1.2: Planning Process, Key Goal 1

Party Comments:

The Joint CCAs support the recommendation from the Kevala DIDF Evaluation and Recommendations[96] to implement an up-to-date known load project database to share with the CEC to facilitate the accuracy of forecasting.[97]

Commission Action: Require the IOUs to share a database of their own known load projects with the CPUC and the CEC. This database will compile and maintain an up-to-date repository of all known load projects which shall be sufficient to track whether specific known load projects

[96] Distribution Investment Deferral Framework: Evaluation and Recommendations, Kevala, Inc. at 15
[97] Opening Comments of [Joint CCAs] Responding to Questions on Track 1 Phase 1 at 6

materialize. The database shall include the following: unique project identifier, impacted circuit, original requested in service date, load amount, forecast in service date, customer type (residential, commercial, industrial), customer load category (Agricultural Water Pump, Mega Tract Homes, Cultivation, Medium/Heavy Duty Commercial EV Charger, etc.), a specific designation if it is a TE related load, what type of TE load (LD/MD/HD/offroad), and an "embedded" or "incremental" designation, among other staff and stakeholder identified data. The data shall be structured in such a way that it allows for the combination of all three IOUs into one database for analysis. We expect that the IOUs will also consider distribution planning when engaging with the IEPR process through CEC proceedings.

Rationale:

- The utilities are required to track known loads in their GNA/DDOR filings pursuant to the June 16, 2022 DIDF Reform Ruling. The ruling directs Utilities to provide additional data in order to determine whether the loads materialize and to identify the types of customer requests that lead to known loads, which will improve alignment between distribution planning and forecasting, including the IEPR forecasts datasets[98]. The May 19, 2023 DIDF Reform Ruling required the utilities to jointly develop a uniform list of type of customer and customer load categories. The utilities are already tracking this data. Providing this database will allow the CEC to have better insight into the granular nature of distribution planning and inform the IEPR load growth forecast.
- By providing known load data to CEC IEPR, the CEC would be in a position to determine how to incorporate this data to inform its load growth forecast, and whether a known load project discounting methodology could and should be employed in the IEPR. A database of known loads tracked over time across entire IOU service territories, and potentially all utility service territories across the state, may be analyzed by CEC to determine an appropriate discount factor for the known loads to be incorporated into the IEPR to account for the difference between top down and bottom-up planning, if warranted. The discount factor can be refined by customer type and customer load category if significant differences are found in service request cancelation rates, as well as by spatial and temporal granularities.[99]

Tentative Timeline: Database available in late 2024.

3.3.7. Facilitate Better Coordination and Data Sharing Between the DPP and Transportation Electrification Work

Related Issues and Goals: Issue 3.1.5: TE Growth, Key Goal 1

Description: Transportation electrification is increasing load on the grid and is forecasted to accelerate capacity demand. This is challenging the current DPP, as described in section 3.2.3.

[98] Administrative Law Judge's Ruling On Recommended Reforms For The 2023 Distribution Investment Deferral Framework Process, The Partnership Pilot And The Standard offer-Contract Pilot, at 10

[99] Green Power Institute Opening Comments On Administrative Law Judge Ruling [Directing Responses To Questions On Track 1 Phase 1] at 31

Efforts are underway at CPUC Energy Division (i.e., the FIP) and elsewhere (i.e., the CEC's EDGE tool, NREL's EVI-Pro tool) to define and locate areas of the grid that will need to be upgraded to accommodate electric vehicles, especially MD and HD EVs, to help California meet its goals. These efforts, while important on their own, require coordination with distribution planning to be put into effect.

Commission Action: IOUs shall be ready to provide any data required to implement the FIP, if adopted, and to incorporate the outputs of the FIP, if adopted, into the DPP.

Rationale: The FIP aims to identify areas of high electric vehicle charging load growth in the 5 to 10 year forecast range to enable proactive planning. The FIP plans to produce outputs that can be incorporated into the DPP, and may use information from the DPP as an input as well. The FIP is still in development as of the release of this staff proposal. However, this staff proposal does include the development of the "Pending Loads" category, which is currently primarily aimed at identifying uncertain but likely loads in years 2 to 4 of the forecast. The pending loads category could be expanded to year 10 of the forecast to incorporate the areas of EV loading identified in the FIP upon its implementation. This would satisfy the requirement to incorporate the outputs of the FIP.

Tentative Timeline: 2024 or 2025 DPEP Cycle

3.4. Commission Oversight

3.4.1. Energy Division Plans for Future Utility DPEP Oversight, Including Potential Funding for Consultants

Energy Division will directly monitor the IOUs DPEPs during this period of historic transition in load growth. Over the next 20 years the California grid expects significant increases in load, potentially growing by 40 percent. Utility distribution planning may require significant changes and adaptability over this period, to adjust to this historical change in load growth. This also calls for more direct oversight from the Commission.

The goal of staff's oversight activity will be to develop and maintain a comprehensive understanding of the IOU's DPEPs to inform ongoing recommendations for how the DPP could be improved. The current staff proposal represents a beginning of this work, but the various issues, goals and proposals described here should be monitored and developed over time. This staff work should encourage the utilities to improve their process through oversight and engagement, rather than the Commission adding detailed requirements on a granular level that may lead to unintended adverse outcomes in a quickly changing environment. For example, staff finds it inadvisable to require the utilities to use a rigid process for load growth forecasting, thus preventing that process from being easily improved in future or from being replaced if it proved unworkable. Ultimately, it is the responsibility of the utilities to conduct adequate distribution planning, and of the Commission to provide oversight and guidance.

Staff will review and discuss the results of the utilities' distribution planning, provided through the current DIDF process. The group will also review the IOUs progress in improving their distribution planning and execution as outlined in this proposal and future Commission orders.

4. Distribution Resources Plan (DRP) Data Portals and Interconnection Capacity Analysis (ICA) — Goals and Procedural History

The IOU Distribution Resources Plan (DRP) Data Portals are interactive web portals providing public access to key information about each utility's electrical grid. Each of the California IOUs leverage extensive geospatial mapping data to create Distribution Resources Plan (DRP) Data Portals that provide this public information. The goals for these data portals are to further the IOUs' efforts to support customer use of clean energy technologies, streamline the interconnection process and help California meet its clean energy goals. To this end, the data available within each portal includes:

- General locations of distribution circuits, substations, and subtransmission systems
- Distributed Energy Resource (DER) Integration Capacity Analysis (ICA) results (i.e., hosting capacity)
- Current, queued, and total distributed generation interconnection amounts
- Downloadable datasets (including API capabilities)
- Location Net Benefit Analysis (LNBA) results
- Grid Needs Assessment (GNA) data
- Distribution Deferral Opportunity Report COR) data
- Historical Public Safety Power Shutoff (PSPS) data
- Future Transmission projects
- High Fire Risk Areas

One of the integral aspects of these data portals is the ICA results they provide access to. ICA is the process by which an IOU estimates how much hosting capacity for new generation, or load[100], is available on the grid. Each IOU uses an iterative analytic methodology to estimate generation and load hosting capacity for each line segment. This knowledge is critical for accurate siting of DERs as well as facilitating faster interconnection.

These Data Portals have undergone multiple iterations to improve their usability and accuracy, especially the ICA portals. As described in Rulemaking 14-08-013 that the CPUC opened in August 2014, the three IOUs were required to publish a DRP by July 1, 2015. In the final guidance for the completion of the DRP, the CPUC ordered each utility to perform an ICA assessment for each line section or node in the distribution system and to perform the Commission-approved Locational Net Benefit Analysis (LNBA) methodology in their distribution systems. The first iteration of the data portals that went live in July 2015 included relatively limited maps. The Data Portals of today are far more advanced, as a result of proceeding activity described in section 4.3, to support specific Use Cases. Use Cases define specific

[100]The IOUs are currently in the process of implementing Load ICA refinements that will not be completed until ~2024-2026. Consequently, activity leading to stakeholders' Load ICA accuracy concerns being addressed satisfactorily is in the early stages.

situations in which a tool could be used. In D.17-09-026 the Commission approved the ICA and Data Portals to address the two primary interconnection use cases:

A. **Loca�ng and Si�ng DERs:** Transparent display of ICA maps to aid third-party DER developers in **iden�fying genera�on interconnec�on and load energiza�on loca�ons where their projects are less likely to trigger costly distribu�on mi�ga�ons or upgrades.** D.17-09-026 further established that ICA results must be adequately representa�ve, and thus capable of informing a DER developer's project design and si�ng. This increasingly includes si�ng of new loads such as EV charging sta�ons, an intended use of Load ICA results that was iden�fied in an ALJ ruling.[101]

B. **Streamlining Interconnec�on of DERs: Providing ICA data that is sufficiently robust to be relied upon to streamline the Rule 21 interconnec�on of DERs.** While the actual streamlining of Rule 21 occurs in R.17-07-007, the DRP and successor High DER proceedings are responsible for the methodological development of the ICA and the publica�on of the ICA data and maps to support the streamlining of Rule 21. Use of Genera�on ICA results in Screen M of Rule 21's Fast Track Ini�al Review process began in 2022. Genera�on interconnec�on applica�ons subject to Screen M (i.e., >30 kW and expor�ng power to the grid) pass the screen and avoid Supplemental Review if the project size is less than or equal to 90% of the Genera�on ICA result. Interconnec�on requests that fail Screen M are subject to Supplemental Review

4.1. Data Available from Portals

The data the IOUs provide in their DRP Data Portals can be classified as being of two general types:

- **Integra�on Capacity Analysis** quan�fies the maximum amount of power that can be injected to, or drawn from, the distribu�on system while requiring minimal to no distribu�on mi�ga�ons, upgrades, or opera�onal restric�ons. The ICA maps have two dis�nct components:
    - **Genera�on ICA** that es�mates how much genera�on could be interconnected at a loca�on.
    - **Load ICA** that es�mates how much addi�onal load could be added at any loca�on.
    - These capacity es�mates are based on automated calcula�ons as determined in D.18-02-004. Further refinements to the Load ICA were ordered by the September 9, 2021, ALJ Ruling.
- **Distribu�on Planning** produces data that can provide visibility into the changing state of the electric distribu�on system through �me, and into distribu�on upgrade ac�vity aimed at maintaining reliability and safety. **Grid Needs Assessment (GNA)** is updated annually in August as part of the Distribu�on Investment Deferral Framework (DIDF) and es�mates future needs that will require either:
    - **Planned Grid Upgrade** projects such as new substa�ons, circuits, or reconductoring. **Loca�onal Net Benefits Analysis (LNBA)** produces a measure of the financial value of deferring such projects. In addi�on to being shared on the Data Portals, informa�on about

[101] Administrative Law Judge's Ruling Ordering Refinements to Load Integration Capacity Analysis, R.14-08-013, September 9, 2021 at 3, 6

planned grid upgrades and LNBA is shared in a DDOR, which is a companion to the GNA report.

- DER projects (e.g., bateries) installed and controlled in a manner to defer or avoid planned grid upgrades.

Depending on the IOU, these have been hosted on separate data portals (PG&E currently has separate ICA and GNA/DDOR portals) or as different layers within one portal. These may be found at:

- **PG&E**: https://www.pge.com/en_US/for-our-business-partners/distribu�on-resource-planning/distribu�on-resource-planning-data-portal.page - this is the landing page for logins to either map
- **SCE:** htps://drpep.sce.com/drpep
- **SDG&E**
  - **SDG&E Login Page:** htps://interconnec�onmapsdge.extweb.sempra.com/
  - **SDG&E Registra�on Page:** htps://www.sdge.com/more-informa�on/customer-genera�on/enhanced-integra�on-capacity-analysis-ica

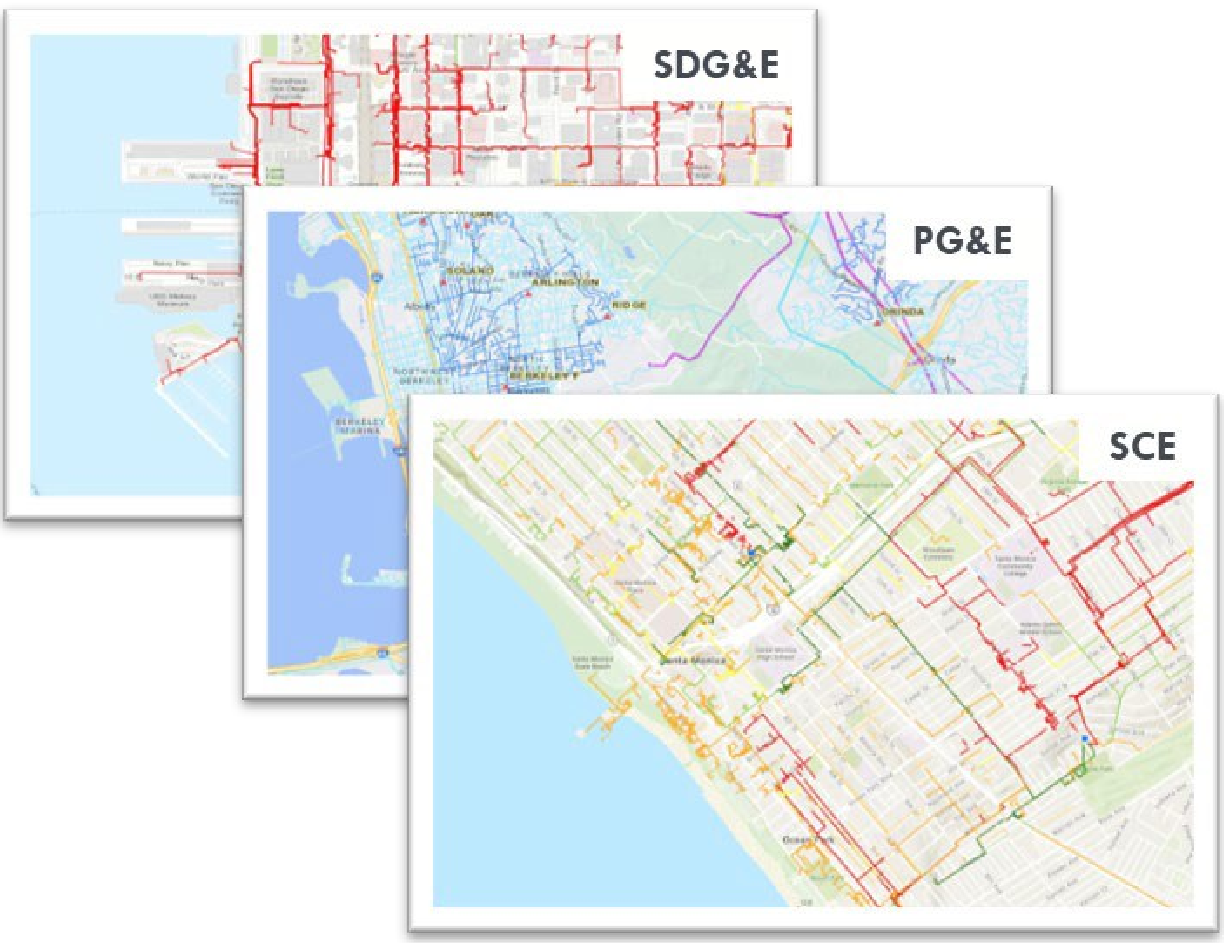


Figure 4-1: Screenshots of the three IOUs' ICA Data Portals

The primary focus of this staff proposal is improving the Generation and Load ICAs, which produce valuable information about constraints for new generation or load due to limits of the electric grid's physical infrastructure and controls. There are many limiting factors for the reliable, safe flow of power on the electric grid. The five key limits considered within ICA are summarized in Table 4-1 Note that each IOU uses slightly different terminology and some have slightly different limits, e.g. SCE and PG&E use +5%,-1.67% for steady state voltage but SDG&E uses ± 5%. Also note that SCE and SDG&E present both a voltage fluctuation and steady state voltage, but PG&E only presents a single voltage limit based on the most restrictive voltage criterion.

At each location on the grid, those limits have implications for how much additional generation or load could be accommodated without first having to modify grid infrastructure or controls. These quantities of additional generation or load are called 'integration capacities' or 'hosting capacities'. Integration capacity analysis (described below the table) is used to calculate estimates of those quantities, thereby providing information essential for maximizing utilization of existing grid resources by increasing the efficiency and effectiveness of efforts to add new generation (e.g., renewables) and new load (e.g., EV chargers). The limiting criteria used by the three IOUs are presented in Table 4-1 below.

Table 4-1: ICA Limiting Criteria by IOU[102]

ICA Study Criteria	Definition[103]	Gen ICA	Load ICA	IOUs' Data Range (Limits) and Terms* **First term is for generation, second (if applicable) for load**
Steady State Voltage (SSV)	Max integration that can be installed without violating Rule 2 (Customer service voltage exceeding ± 5% on a 120V base.) [104]	X	X	PG&E IC Voltage: ± 5%, -1.67% (for both gen and load) SCE SSV and SSV Load: ± 5%, -1.67% SDG&E ICA Voltage and Load Voltage: ± 5%
Voltage Fluctuation	Max integration that can be installed without causing a voltage variation of limit.	X	X	PG&E: ± 3% SCE Voltage Fluctuation and Voltage Variation Load : ± 3% SDG&E ICA Voltage: ± 3% (no limit for load)
Thermal	Max integration that can be installed without causing thermal overloads on equipment.	X	X	PG&E: IC Thermal (for both gen & load) SCE: Thermal & Thermal Load SDG&E: ICA Thermal & Load Thermal
Protection	Max generation that can be installed without causing loss of end of line (EOL) visibility on our protection devices that can be hazardous to line crews.	X		PG&E: IC Protection SCE: Protection SDG&E: ICA Protection
Operational Flexibility	Max generation that can be installed without causing reverse power flow (backfeed) at SCADA devices.	X		PG&E: IC Safety SCE: ICA Op-Flex SDG&E: ICA Op-Flex

*Generation is further split between uniform (constant generation over 24 hours) and generic solar (following a typical monthly solar generation profile every day)

4.2. ICA Estimation Process

Power flow simulation is the core of ICA. First a power flow simulation model is built without any new generation or load. Each of the five key limits is evaluated independently. To begin the evaluation of thermal limits on Generation ICA, a small increment of new generation (i.e., 10 kW or 100 kW but the exact value varies based on conditions) is incorporated into the model, and output is scrutinized for any violation of thermal limits. If no such violation is observed, additional increments of new generation are incorporated into the model between successive power flow simulation analyses until violation of a thermal limit occurs. The largest total quantity of new generation that does not produce violation of a thermal limit is the Generation ICA thermal limit.

A similar series of iterative power flow simulation analyses are used to determine the Generation ICA steady state voltage limit, and all the other Generation ICA limits. The overall Generation ICA result is equal to the minimum of the five test-specific Generation ICA limits. The test violation (e.g., Thermal, Steady State Voltage) associated with the overall Generation ICA result is called the limiting criterion, or the limiting test. Load ICA is performed in a similar manner, the difference being that small increments of new load are incorporated into the model between successive power flow simulations, and only thermal and voltage tests are applicable. This process is shown in Figure 4-2Figure 4-2. [105]

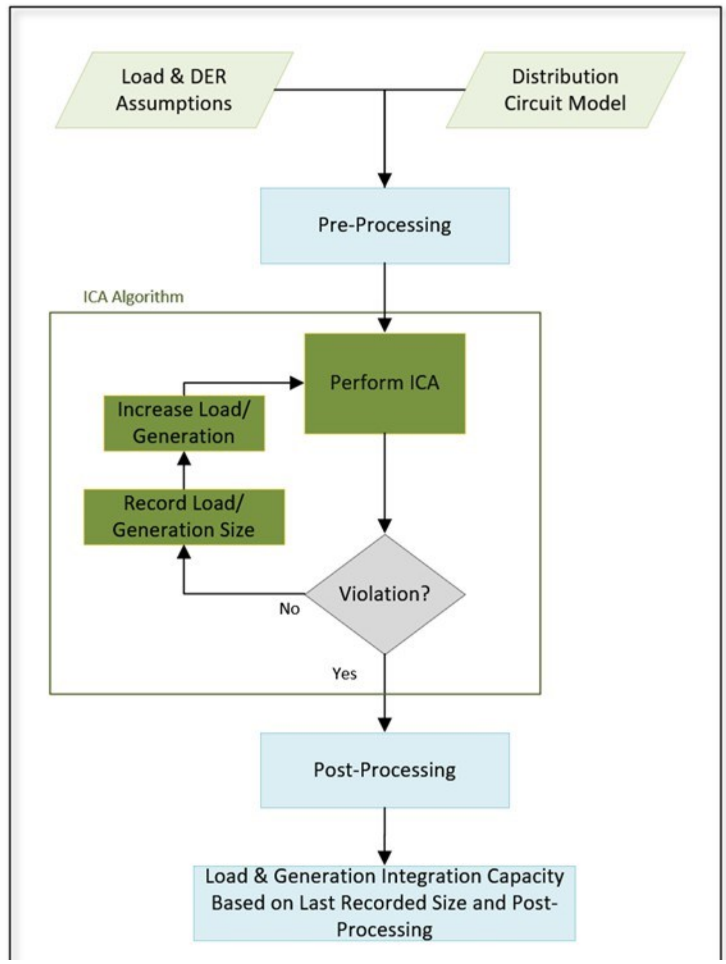


Figure 4-2: ICA Iterative Methodology

The results of the ICA are then published by the IOU on their DRP Data Portal. Project developers can then access the ICA results via the DRP Data Portals to estimate the amount of generation or load that might be interconnected to the utility grid at any specific location without triggering grid mitigations or upgrades. This information can be used to help identify specific sites that might be easier to interconnect at than others. For example, a

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[102] Source: PG&E- ICA Map User Guide, Version 1.11, June 27, 2022

[103] The definition below comes from the PPT, "High DER SCE Training for ED Staff ICA Methodology and External Portal," on Oct. 30, 2023.

[104104] At SCE's recommendation, an ALJ Ruling issued on September 9, 2021 approved increasing the lower bound of SSV from 114 V (-5%) to 118 V (-1.67%) to account for secondary voltage drop.

[105] From SCE High DER SCE Training for ED Staff ICA Methodology and External Portal, October 30, 2023

developer looking to install several fast EV chargers along a heavily travelled corridor could use the Load ICA maps to help decide which exit in a particular town has the most grid capacity to support those chargers.

It is important to state that ICA is intended to be an information tool to support the generation interconnection and load energization processes. Project applicants want to identify sites for their projects with sufficient capacity to ideally avoid costly interconnection upgrades and save time in either the interconnection or energization process. Changing the interconnection and energization processes and procedures is not in scope of this proceeding, and thus, is out of scope of this staff proposal.

Once a developer has selected a site, they submit a generation interconnection or new load energization application to the utility. The utility then reviews the application and may contact the developer to confirm or revise the application. Once the application is complete, the utility may perform a detailed study to determine if the grid can support the new generation or load. For generation, if the requested capacity does not violate any of the five criteria, the interconnection request can be fast tracked via Rule 21 Screen M.[106] Load ICA does not currently have such an automatic approval process for energization. If upgrades or other mitigations are needed they must be completed before the new load or generation can be connected to the grid.

There is currently no publicly available direct feedback loop from Utility Review to inform changes to the ICA. That causes two potential issues:

1. Users do not have reliable data to assess the accuracy of the ICA beyond their own experience or anecdotal evidence, reducing the effectiveness of the ICA.
2. Utilities do not continuously compare interconnection or energization processes to the ICA to improve the alignment of the ICA to these processes.

Adding that feedback loop is shown in red in Figure 4-3 as well as the interconnection or energization process. Some of the proposals below intend to help enable this feedback and allow ongoing ICA assessments informed by real-world experience and intended to eventually allow for improving the future accuracy and usefulness of ICA. Analysis of the accuracy limitations of the ICAs can be found in sections 2.4.3, 2.5.1, 3.2, and 3.3. The eight refinements ordered by ALJ Ruling Joint Parties' Motion for an Order Requiring Refinements to The Integration Capacity Analysis described in the following section are one example of this type of feedback mechanism. Continuing and expanding that type of feedback is a driver of many of the data portal improvement proposals in this staff proposal.

[106] More information on Rule 21 can be found here: [Rule 21 Interconnection (ca.gov)]

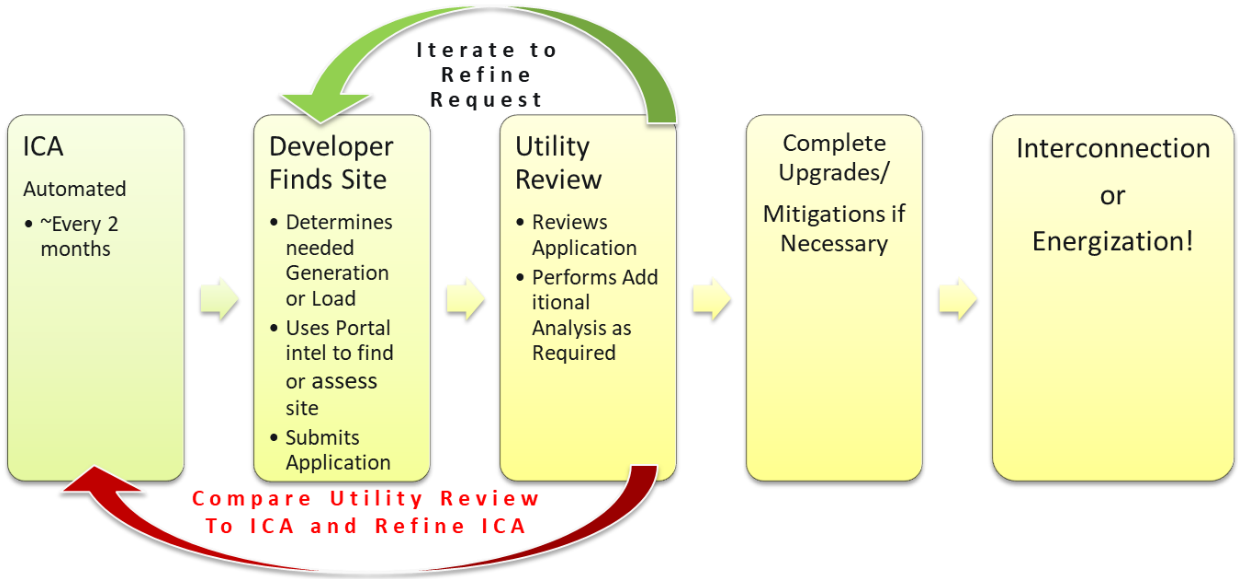

Figure 4-3: ICA Results Use in Interconnection/Energization Process

4.3. Data Portals Procedural Background

This subsection presents the procedural history of the DRP Data Portals. These portals were developed and influenced by multiple CPUC Decisions and Rulings spanning several proceedings. The development of the DRP Data Portals began on August 14, 2014, when the Commission opened Rulemaking (R.) 14-08-013. The purpose of this Rulemaking was to guide the IOUs in developing their Distribution Resources Plan (DRP) Proposals in accordance with Assembly Bill 327 [107] In the Scoping Ruling for Rulemaking R.21-06-017, Track 1 (Distribution Planning and Execution Process and Data Improvements) Phase 1 (Near-Term Actions), the schedule directs a Staff Proposal followed by a Staff Proposal Workshop in the fourth quarter of 2023.[108]

The Data Portals section of the Staff Proposal aims to answer Question 4 in the Scoping Memo:

"How should Integration Capacity Analysis data and calculations be improved to enhance accuracy and usefulness for DER planning, siting, and interconnection, especially with respect to electrification load?

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[107] The Public Utilities Act requires each electrical corporation, as a part of its distribution planning process, to consider specified nonutility owned distributed energy resources as an alternative to investments in its distribution system to ensure reliable electric services at the lowest possible costs.

This bill would require an electrical corporation, by July 1, 2015, to submit to the commission a distribution resources plan proposal, as specified, to identify optimal locations for the deployment of distributed resources, as defined. The bill would require the commission to review each distribution resources plan proposal submitted by an electrical corporation and approve, or modify and approve, a distribution resources plan for the corporation. The bill would require that any electrical corporation spending on distribution infrastructure necessary to accomplish the distribution resources plan be proposed and considered as part of the next general rate case for the corporation and would authorize the commission to approve this proposed spending if it concludes that ratepayers would realize net benefits and the associated costs are just and reasonable.

[108] Assigned Commissioner's Amended Scoping Memo and Ruling at 10

Should the Data Portal design be improved to provide access to data for multiple stakeholders in the distribution planning process (DPP)?"

Other proceedings that informed the development of the data portals include D.20-09-035 in R.17-07-007 (Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21). The D.20-09-035 Decision modified Electric Tariff Rule 21 of PG&E, SCE and SDG&E, which directs the interconnection of Distributed Energy Resources. The key objective in adopting modifications in the Decision was to incorporate the Integration Capacity Analysis results from R.14-08-013 and streamline the interconnection.109

Development of the data portals was also informed by policy in the Transportation Electrification proceeding R.18-12-006 (Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification). This Rulemaking aimed to provide guidance on parameters for new transportation electrification programs and resolving key outstanding issues. The proceeding focused on establishing a framework for IOU investments in Transportation Electrification in California which align with the goals of SB 350.[110] Expediting the refinements in Load ICA to support developers searching for sites with grid capacity to place Electric Vehicle Supply Equipment (EVSE) was informed by the work being done in R.18-12-006.

The Assigned Commissioner Ruling (ACR) provided guidance on the content of the DRPs which were filed by July 1, 2015.[111] After the DRP applications were filed by the IOUs and stakeholders had an opportunity to respond, the Staff published a Distribution Resources Plan Roadmap Straw Proposal on November 2, 2015. The purpose of the Straw Proposal was to provide input into the Scoping Memo for the DRP proceeding. Additionally, it attempted to integrate the efforts in various proceedings, in particular, the Integrated Distributed Energy Resources proceeding (R.14-10-003)[112]. An ALJ Ruling on November 16, 2015, invited party comments on the Straw Proposal.[113] The Scoping Memo established three tracks which included:

Track 1: Methodological Issues

Track 2: Demonstration and Pilot Projects

Track 3: Policy Issues

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[109] Ordering Paragraphs 2, 4, 5, 11 and 12 incorporated the ICA data in the interconnection process. SCE's compliance with these Ordering Paragraphs were affected when SCE determined that Generation ICA values were generated by Release 3 could be erroneous and hence not acceptable to be utilized in the interconnection process. SCE filed for a 180-day extension to comply on August 19, 2022 which the Commission granted on September 18, 2022. In SCE's November 2022 update, SCE determined the profile methodology to be the sole root cause of the errors. Load was underrepresented and as a result, DER resources were being double counted. Mitigation of the data errors was addressed in the Release 4 platform.

[110] Transportation Electrification Activities Pursuant to Senate Bill 350
Clean Energy and Pollution Reduction Act of 2015. This act provides broad directives in 5 major policy areas. One of the areas is Transportation Electrification. Implementation of SB 350 in Transportation Electrification approval of transportation electrification programs as well as testing of a new electric vehicle rate.

[111] ACR filed on August 14, 2014 at 1.

[112] ALJ Ruling on 16 November, 2015.

[113] Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge filed July 1, 2015.

Track 1 included issues related to the ICA, Locational Net Benefit Analysis (LNBA) and authorization of Demonstration Projects A and B. These projects focused on research and improvement of ICA and LNBA methodologies.[114]

The IOUs were ordered to publish initial, limited ICA results via online maps by an ALJ ruling in February 2015. In July 2015 the IOUs published the initial, limited ICA results via online maps. Those were the first iteration of what would become the DRP Data Portals.

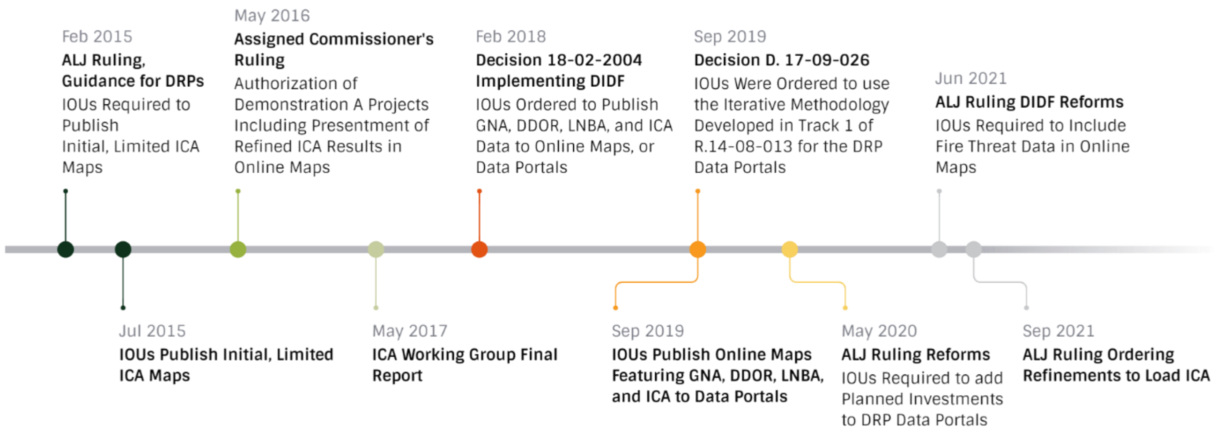

Figure 4-4: DRP Data Portals Timeline and Procedural Background

The May 2, 2016, Assigned Commissioner Ruling authorized Demonstration Projects A and B, with details on the ICA and LNBA refinements in Attachment A of the Ruling. This Ruling was further refined in a subsequent Ruling by the Assigned Commissioner on August 23, 2016. This refined the methodology used for both ICA and LNBA.

The ICA Working Group reviewed Demonstration Project A results and submitted a Final Report on May 15, 2017.[115] Many recommendations were submitted, including those designed to account for queued projects in the online maps and address operational flexibility requirements. The ICA Working Group members also proposed that the IOUs should design, document, and implement QA/QC plans to ensure that ICA results are accurate and useful. The types of QA/QC activity envisioned for the ICA included discussion of methods and assumptions with stakeholders, comparison of independent ICA results with other stakeholders, and comparison of ICA results with operational data points of intended use (e.g., evaluation of the effectiveness of use of calculated ICA results within Screen F (short circuit

[114] The scope of issues included: development of ICA and LNBA methodologies, frequency and method of updating ICA and LNBA, how the methodologies will be utilized, limitations on the use of the ICA and LNBA methodologies, whether the LNBA correctly evaluates the avoided cost of DER deployment, whether the LNBA accurately values costs and benefits of DER integration, means to insure that the LNBA and ICA results will be integrated into a single display to provide information in optimal locations, associated confidentiality and security issues, definition of the method by which LNBA and ICA results would be included in tariffs or other valuation for grid services, and whether to approve Demonstration Projects A and B proposals.
[115] California Distributed Resources Plan (R. 14-08-013) Integration Capacity Analysis Working Group Final ICA WG Long Term Refinements Report

contribution) of the Rule 21 Fast Track process).[116] D.17-09-026 introduced the ICA Working Group Report and the LNBA Working Group Report into the record and made policy recommendations based on the reports.[117]

In D.17-09-026 the Commission adopted the ICA use cases for online maps and interconnection streamlining and distribution planning. The methodology adopted in D.17-09-026 for the ICA specified how to calculate the available load and generation hosting capacity at every node based on the thermal, steady state voltage, voltage fluctuation, operational flexibility, and circuit protection limits.

Subsequent Decisions, such as D.18-02-004, continued to refine the ICA methodology and the data portals. In this Decision, the Commission ordered the IOUs to develop a central DRP Data Access Portal with tables to view the ICA, LNBA, GNA and DDOR data on the circuit map. The IOUs were ordered to propose workplans for implementation of the DRP data access portals via a Tier 3 Advice Letter.

To support DER planning, display in the online maps of the location of approved transmission projects was ordered in a May 11, 2020, ALJ ruling. Additionally, new map layers for fire threat and tree mortality data were required. The May 2020 ruling specified the source of these data be the online Commission FireMap. However, a June 21, 2021 ALJ ruling provided the utilities the option to use their own FireMap data so long as the source was identified.

Finally, on September 9, 2021, an ALJ Ruling ordered three minor modifications and five modeling refinements to Load ICA:

- Minor Modifications
  - PG&E: Decrease the lower limit of the Steady State Voltage Criteria from 119 V to 118 V
  - SCE: Increase the lower limit of the Steady State Voltage Criteria from 114 V to 118 V
  - SDG&E: Integrate anticipated known loads at specific locations
- Load ICA Modeling Refinements
  - Model Load ICA with all queued load projects and planned, known, near-term distribution system projects
  - Model Load ICA to include distribution system upgrades with an approved construction schedule and an in-service date within one year
  - Model Load ICA to consider forecasted DER growth
  - Model Load ICA to consider planned network reconfiguration
  - Model Load ICA with load forecast for the next year

The utilities were ordered to prepare annual updates to notify the Commission and stakeholders of progress on development and implementation of the refinements.

[116] California Distribution Resources Plan (R. 14-08-013) Integration Capacity Analysis Working Group Final ICA WG Long Term Refinements Report at 5.
[117] D.17-09-026 at 11.

5. ICA and Data Portal Improvements

This section presents a collection of proposals to improve the ICA specifically and the Data Portals in general. These improvements are intended to enable the ICA and other Data Portal layers to better support the Use Cases for these portals. To guide development of these proposals, three Key Goals (below) were developed based on the scoping memo and ruling[118].

The improvements are organized by priority in their respective sections. Implementation of the approved improvements can start immediately and shall be completed within 2 years.

5.1. Issues Before the Commission

The scoping memo posed the following questions concerning IOU data portals (***emphasis*** is added):

> *"4. How should Integration Capacity Analysis data and calculations be improved to **enhance accuracy** and **usefulness** for **DER planning, siting, and interconnection**, especially with respect to electrification load? Should the **Data Portal design be improved** to provide access to data for multiple stakeholders in the DPP?"*

The questions in the scoping memo imply two Key Goals of changes proposed for the data portals:

- **Data Portals Improvement Key Goal 1 -– Enhance Usefulness**: Several characteristics of ICA results and the data portals determine their usefulness. Accuracy is arguably the most important characteristic. However, other characteristics also influence ability to use ICA results for the use cases. For example, the level of detail at which ICA results are presented is one such characteristic. Additional contextual information is another.
  - **Increase Accuracy**: For users of Generation ICA and Load ICA results obtained from a data portal, accuracy refers to agreement of ICA results with the hosting capacity determined by utility engineers who process interconnection/energization applications. This is who makes the final decisions about the need for any possible mitigations.[119] Both use cases require that the ICA maps align well with comparable information developed by distribution engineers. Stakeholders currently lack sufficient information to compare ICA results to outcomes of hosting capacity and mitigation needs assessments completed by distribution engineers following applications for interconnection. Therefore, a key component of this goal is to first provide stakeholders data on interconnection and energization outcomes compared to the ICA results to build confidence as well as a first step towards improving the

[118] Assigned Commissioner's Scoping Memo and Ruling, R.21-06-017, November 15, 2021.

[119] For some other stakeholders, accuracy could mean something different. For example, one possible alternative definition for ICA accuracy is how well the procedures used to develop the data on the ICA portals follow the agreed upon approaches. This alternative could also be referred to as 'process conformance quality'. Data validation is a central element of ICA procedures. Review of ICA data validation plans and ICA data validation efforts was the focus of reports that Quanta Technologies published for each IOU in Q2 2021 as the 'Integration Capacity Analysis Data Validation Plan Assessments'. These were important assessments that helped identify process improvements that each IOU started to implement towards the goal of ensuring that ICA data validation follows best practices. However, following the agreed upon procedures may still produce ICA results that do not represent the outcomes a customer interconnecting new generation or load experiences.

accuracy of ICA results. That will also provide data to iden�fy how ICA data sources and/or calcula�ons could be improved to increase accuracy in predic�ng a customer’s interconnec�on or energiza�on experience. Improving or enabling the improvement of accuracy using this defini�on is a focus of this staff proposal because the previous work by Quanta already inves�gated enhancing process accuracy.[120,121,122] As stated in those reports, ”Quanta completed a valida�on study for each IOU as ordered by the California Public U�li�es Commission in Rulemaking (R.) 14-08-013 on January 27, 2021. The ruling ordered the investor-owned u�li�es (IOUs) to retain an independent technical expert within 60 days of the ruling to review their ICA data valida�on plans and review the IOU’s data valida�on efforts. Quanta Technology was selected as the independent technical expert.”

    - **Increase Level of Detail and Context**: Providing greater detail and context may enhance stakeholders' understanding of likely implica�ons of the results, thereby making the informa�on in the ICA maps more useful. An example of such detail is iden�fying the limi�ng test(s) that is/are driving each ICA result. In addi�on, convenient access to detailed hourly results in bulk may enable researchers or other stakeholders to perform their own analyses, the results of which may contribute to future improvement of ICA.

- **Data Portals Improvement Key Goal 2 - Improve Design (or Usability)**: The data portals convey large quan��es of very technical informa�on. As such, their effec�veness hinges on users' ability to navigate the portals and access and understand the informa�on without undue difficulty. The data portals encompass a wide range of design and usability considera�ons. Are support resources (e.g., User Guides) readily available, clear, and complete? Do data portal elements such as tables and charts conform to best prac�ces in areas such as variable naming, forma�ng, and labeling? Do maps employ legends and labeling that are unambiguous? Improvements to data portal design and usability can be expected to increase the benefits for users.

5.2. Information Used to Develop Data Portal Improvement Proposals

The Generation and Load ICA improvements proposed below were synthesized based on input from several sources including:

- **Stakeholder Interviews**: Staff’s consultant Verdant Associates conducted interviews with stakeholders and users of the data portals in mid-2022. These interviews included Community Choice Aggregators (CCA), public agencies including the Public Advocates Office, trade organiza�ons, and EV, storage, and solar developers. Verdant has also discussed the data portals in depth with each of the three electric Investor-Owned U�li�es.

- **Public Workshops**: Feedback from two public workshops provided input on how data portals could be improved. These workshops were:

[120] PG&E Integration Capacity Analysis Data Validation Plan Assessment, Prepared by Quanta Technology for CPUC Energy Division, June 24, 2021
[121] SCE Integration Capacity Analysis Data Validation Plan Assessment, Prepared by Quanta Technology for CPUC Energy Division, June 24, 2021
[122] SDG&E Integration Capacity Analysis Data Validation Plan Assessment, Prepared by Quanta Technology for CPUC Energy Division, June 24, 2021

- The Data Portals Workshop for the High DER Grid Planning Proceeding on July 26, 2022[123]
- The Load ICA Refinements Joint IOU/Energy Division Workshop on March 8, 2023[124]

- **Stakeholder Comments**: Stakeholders have provided though�ul comments in response to several Rulings in the High DER Proceeding. The majority of relevant comments for the Data Portals were in response to Ruling 2 (Issued 4/6/2023) that asked several ques�ons concerning Track 1, Phase 1 of the proceeding.
- **Verdant and CPUC Staff Research**: Staff's consultant Verdant Associates in partnership with CPUC ED staff issued several data requests to collect informa�on to support these proposals. Some of these data were combined with other sources to provide quan�ta�ve analysis, some specifically focus on the accuracy of the data portals.

5.3. Generation and Load ICA and Data Portal Improvements

5.3.1. Incorporate More Detail of the Limiting Criteria into ICA Results in the Data Portal Maps

Description of Issue: Generation and Load ICA map summary data indicating zero/low hosting capacity may drive developers to not install DERs at a location due to potential distribution upgrade costs and delays. This often leads to developers not moving forward or asking the utilities for more in-depth information about the siting of new DERs or loads in the location. However, not all zero/low available hosting capacity values require a distribution grid upgrade and many locations can accommodate more load or generation with a relatively quick and inexpensive mitigation activity. The value of a numeric ICA result can be maximized if the information provided from the ICA includes more information on the type of limit (e.g., thermal, voltage) upon which the overall result is based.

Developers use ICA results to assess desirability of specific locations for prospective projects. When a project is larger than the ICA hosting capacity for a specific location, consideration of likely cost and schedule impacts of necessary mitigations is one element of a comprehensive assessment of site desirability. Mitigation of a voltage violation might be accomplished relatively quickly at low cost by changing settings of distribution equipment, whereas mitigation of a thermal violation could necessitate higher-cost measures with larger schedule impacts. An example of this is a utility charging only $2,500 to change settings vs. a $30,000 transformer vs. millions of dollars for new substation. Convenient access to information about the type of limit driving ICA results is necessary to enable a comprehensive interpretation and evaluation of the likely implications of ICA results for a proposed project.

Data portal map popups containing ICA results currently do not include the type of limit (e.g., thermal, voltage) that is constraining generation or load hosting capacity. The type of limit can be determined by analyzing detailed, hourly ICA results that are saved in CSV files for individual feeders/segments. These

[123] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/distribution-planning/july26dataportalsslides.pdf

[124] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/distributed-energy-resources-action-plan/load-ica-refinements-workshop-slides.pdf and https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/distributed-energy-resources-action-plan/joint-iou-presentation--load-ica-refinements-workshop-3823.pdf

files may be downloaded from the map. However, many developers do not possess the expertise to do that analysis or an understanding of the typical impact of each type of limit on the cost and schedule for needed mitigations.

Use Case: Locating & Siting DERs. This additional information will help developers understand when insufficient generation or load capacity might have a potentially viable mitigation solution that does not require an expensive upgrade.

Responsibility: PG&E, SCE, SDG&E

Data Portals Key Goal 1: Increasing Usefulness of the ICA and data portals by providing more limiting criteria information within the map summary to help developers understand where additional capacity might be accessible in locations that are listed on the ICA maps as capacity constrained.

Party Comments:

- Clean Coali�on supported this in their Ruling 2 Comments RE: Ques�on 10: “The primary ques�on is what the specific constraint causing the low hos�ng capacity is, which is what will determine the possible remedies. The ICA User Guides state that either thermal, voltage, distribu�on protec�on, or opera�onal flexibility viola�ons could be the issue, but the maps don’t currently show the specific viola�on limi�ng the integra�on of genera�on. This is not user friendly; a developer should not need to download data or reach out to u�lity engineers to get clarity. Instead, each feeder segment should be more transparent and indicate the limi�ng factor to the integra�on of more genera�on. With informa�on about the limi�ng constraint, the next ques�on is what the cost of the upgrade will be, whether there is a behind- the-meter (“BTM”) solu�on that might avoid the upgrade, or if downsizing the project is possible. Depending on the cost and �meframe to implement solu�ons, a developer might prefer to search for another loca�on rather than work to develop a project at a site with 0 kW of hos�ng capacity.”
- Green Power Ins�tute GPI expressed support for this in their Ruling 2 Ques�on 15 response: “Cri�cal improvements, ordered by importance: 1. Accuracy and ac�onable ICA data” – adding these data will help make the ICA more ac�onable and help guide accuracy improvements.

Commission Action: Commission should direct the IOUs to add the limiting criteria (e.g., thermal, voltage) to data portal map popup window displays of ICA results to enable the user to understand the low and zero hosting capacity results. While each utility has a slightly different set of criteria, limiting criteria can be broadly categorized as either **thermal** or **voltage** for Generation and Load ICA maps plus **protection** and **operational flexibility** (or safety) for Generation ICA maps. Information about how the different limiting criteria typically impact interconnection timelines and costs should be provided either in the map or in the User Guide to help data portals users interpret the results. Additionally, each IOU shall include explicitly in their user guides the numerical value for each limiting criterion as shown previously in Table 4-1.

Rationale: Increased transparency of the limiting criteria will contribute to deeper understanding and ability to utilize the reported summary ICA result. Different types of limits have different implications for possible mitigation schedule and cost but this information is not currently featured in the data portal map popup window displays of ICA results. While information necessary to identify the limiting criteria is available in downloadable data files, background knowledge and analysis of those data is required to identify and understand the limiting criteria; a task that currently limits customer usage. Given the importance and relative ease of adding this information to the data portal map popups and to the User Guides, this proposal should be pursued to increase the value, transparency and usability of the ICA and data portal maps. The additional data will enable better use of existing hosting capacity on the grid to interconnect more DERs or loads.

Verdant found that only a minimal percentage of applications for interconnection to line segments with insufficient ICA hosting capacity led to a distribution upgrade. IOU input indicates that the majority of applications where hosting capacity was constrained were limited by voltage constraints that are often remedied with distribution equipment settings changes or circuit configuration modifications. Thermal constraints are more likely to require a distribution upgrade. A review of 99 interconnection applications from 2022, where hosting capacity was smaller than the proposed PV size, found that few applications (30%) necessitated a distribution mitigation or upgrade: <u>a counter-intuitive result</u>. Information about the type of limiting criteria was available for **12 of these 99 applications, and all 12 had a voltage limitation. While all 12 of these applications were for PV systems larger than the ICA hosting capacity, only 2 required a distribution upgrade or mitigation.** Details of the review are included as Appendix B.

5.3.2. Remove All PG&E and SDG&E Registration Requirements for Data Portal Access

Description of Issue: Data portal registration requirements diminish the accessibility and effectiveness of the DRP Data Portals by limiting how quickly and conveniently users can access data. SDG&E and PG&E require users to register a username and password to access their DRP Data Portals. SCE does not require users to register to access its DRP Data Portals, creating inconsistency in requirements among the utilities. PG&E requires users to register with an email, name and password, and the registration is automatically approved. For SDG&E, the time to obtain login credentials can be weeks, as documented by Verdant and reported by at least one stakeholder. In addition, SDG&E requires registrants to provide personal information (e.g., job title, phone number) and periodically initiates a de-registration protocol, requiring occasional users to take additional action to maintain access to the data portal. These requirements, particularly SDG&E's, limit the accessibility and effectiveness of these portals by limiting how quickly and conveniently users can access data.

Use Cases: Both **Locating and Siting DERs** and **Streamlining Interconnection** should be improved by providing easier access to the data portals.

Responsibility: PG&E, SDG&E

Key Data Portal Improvement Goal 2 Increasing Usability by reducing the barriers to using the data portals, stakeholders will be able to make better use of the portals.

Party Comments:

- GPI supported this in their Ruling 2 Comment RE: Ques�on 10: “Registra�on requirements present hurdles to accessing the maps and are unnecessary. PG&E and SDG&E should remove their registra�on requirements.”
- IREC also showed support in their Ruling 2 Comments RE: Ques�on 10: “Recommend: Registra�on requirements at u�lity’s discre�on but should obtain access within 24 hrs. If re-registra�on is required, the u�lity should demonstrate the security reason for the requirement.”
- CCA showed support in their Ruling 2 Comments RE: Ques�on 10: “Recommend: Standardiza�on of access to data portals and immediate access to the portal.”
- UCAN showed support in their Ruling 2 Comments RE: Ques�on 10: “Need �mely and accurate data for TE and dynamic rates. This prevents poten�al ratepayer savings. The Commission should resolve the data access and accuracy issue soon.”
- Center For Biological Diversity, The Climate Center, 350 Bay Area, The Clean Coali�on, Vote Solar, and Sierra Club also showed support in their Ruling 2 Comments RE: Ques�on 10: “Each IOU should provide ICA map access without having to sign up or request access.”
- Finally, the Clean Coali�on showed support in Ruling 2 Comments RE: “Recommends no registra�on requirements.”

Commission Action: Require IOUs to remove registration requirements to access the data portals. SCE currently allows portal access without registration, so PG&E and SDG&E should similarly do so.

Rationale: SCE has operated its data portal for several years without any registration requirements. The consensus among stakeholders is that increased standardization increases usability, and numerous stakeholders advocated specifically for the elimination of data portal registration requirements.

5.3.3. Utilities should Utilize the 15/15 Rule, not the 15/100/15 Rule, for Decisions about Data Redaction Protecting Individual Customer Privacy for the ICA, GNA, and DDOR

Description of Issue: Under certain circumstances, results of Integration Capacity Analysis (ICA), Locational Net Benefits Analysis (LNBA), Grid Needs Assessment (GNA), and the DDOR (collectively, “ICA/DIDF”), could be used to identify loads of individual customers. Data redaction protocols are in place to avoid this unacceptable outcome. These protocols are designed to balance the competing goals of data transparency and individual customer privacy. In a July 2018 ALJ Ruling, the CPUC ordered the IOUs to use the 15/15 Rule to guide the redaction of ICA/DIDF results.

The 15/15 Rule requires that information in a data set be made up of at least 15 customers, and any single customer’s load must be less than 15% of an aggregation category. For ICA/DIDF, redaction policies are applied to feeders supplying groups of customers from various sectors. While SCE and SDG&E use the 15/15 Rule, PG&E uses its 15/100/15 Rule, which includes the additional requirement that a data set include at least 100 residential customers. PG&E's use of its 15/100/15 Rule results in substantially more data redaction than the 15/15 Rule, impeding electrification and DER integration efforts by redacting GNA results, select ICA results, and load profile data for approximately 24% of PG&E’s circuits.

The 15/100/15 Rule's requirement for at least 100 residential customers creates a substantial risk of excessive redaction. For example, if load data for 16 non-residential customers and 1 residential customer on a feeder were summed [and no single customer made up more than 15% of the total load], the circuit would be subject to redaction because fewer than 100 residential customers contributed load data to the total. In the above example, the requirement for 100 residential customers is not necessary to protect confidentiality of individual customers: when applied to the data for the 17 customers on the feeder, the 15-customer and 15-percent provisions of the 15/15 Rule are sufficient. Results of ICA/DIDF analyses create value only if they can be accessed and used. Excessive redaction produced by the 15/100/15 Rule creates unnecessary barriers to the data portals assisting project developers and benefiting customers and ratepayers.

A substantial portion of PG&E feeders are exposed to the risk of excessive redaction by the 15/100/15 Rule. **Approximately 24% of feeders in PG&E territory (718 of 2971) have fewer than 100 residential customers,** and thus would likely have their GNA results, generation profiles and hourly Generation ICA (with Operational Flexibility) results redacted regardless of the number of customers in other sectors (e.g., commercial, industrial, agricultural) that are on the feeder. For reference, **PG&E currently has 34% of circuits redacted in their 2023 GNA filing whereas SCE only has as estimated 23% circuits redacted, similar to SDG&E at 24%.**[125] Reverting to the 15/15 Rule would assure confidentiality of individual customer information at the level ordered in the July 2018 ALJ Ruling, which is the level that is currently provided by SCE and SDG&E.

Use Cases: **Locating and Siting DERs,** especially of new loads such as for electrification**,** will be improved by providing stakeholders information on more circuits by reducing the number that are redacted. Without information on these circuits, stakeholders cannot make use of the data portal functionality.

Responsibility: PG&E

Data Portals Key Goal 1 - Enhance Usefulness. Reducing the number of circuits and nodes that are redacted will allow stakeholders to make better use of PG&E's GNA and ICA maps.

Party Comments: The relatively high number of redacted PG&E circuits, especially in rural areas, was noted in stakeholder interviews conducted by Verdant in 2022. Stakeholders noted that these redactions can impede siting new loads, especially for transportation electrification.

Commission Action: Require all IOUs to use the 15/15 Rule for data redaction protecting individual customer privacy, as ordered by July 2018 ALJ Ruling. PG&E shall no longer apply the '100 Residential Customers' 15/100/15 Rule in parallel with the 15/15 Rule, and instead shall employ the 15/15 Rule for data redaction as ordered by July 24, 2018, ALJ Ruling, Appendix A ("ALJ Ruling on PG&E Matrix").

Rationale: Excessive redaction of GNA results limits the full use of Load ICA results in cases where a DER project is planned to come online a few years later. In an appendix of PG&E's ICA User Guide, the methodology for combining Load ICA results and GNA forecast data is described. PG&E does not use the 15/100/15 Rule to redact all Load ICA results, but it is used to redact the GNA results necessary for a

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[125] Based on Redaction of Feeders in the 2023 Grid Needs Assessment Reports

34%	PG&E	0.34 = 1036/2985	PG&E lists all feeders in GNA report
23%	SCE	0.23 = 80/348	SCE lists only feeders with a grid need, so 23% is an estimate
24%*	SDG&E	0.24* = 96/400	SDG&E estimate based on a sample of feeders in confidential GNA report

complete analysis of a location's load hosting capacity. Therefore, reducing PG&E's DRP Data Portal's usefulness for enabling energization of new loads such as EV charging.

For ICA/DIDF data, PG&E was ordered in a July 2018 ALJ Ruling[126] to use the 15/15 Rule that the Commission established in D.97-10-031[127] and D.14-05-016[128]. The 15/15 Rule requires that information in a data set be made up of at least 15 customers, and any single customer's load must be less than 15% of an aggregation category. The 1997 and 2014 decisions addressed data aggregation situations that differ from the ICA/DIDF data aggregation situation. As such, the contents of those decisions had to be adapted for use with ICA/DIDF. PG&E's 15/100/15 Rule adding the requirement that information in a data set must contain data for more than 100 residential customers is one possible adaptation of contents of the 1997 and 2014 decisions, but not the adaptation ordered by the July 2018 ALJ ruling.

5.4. Generation ICA and Data Portal Improvements

5.4.1. Modify ICA Maps to Enable Straightforward Customer Creation of Limited Generation Profiles (LGPs)

Note: This proposal 1.4.1 is related to proposal 5.4.2 ('Modify ICA Methodology to Make use of LGP Application Information.') This proposal is focused on allowing customers to easily create LGP information, whereas proposal 5.4.2 is focused on ensuring the IOUs include LGP information in their ICAs.

Description of Issue: The data portals and ICA currently emphasize a single, annual minimum ICA result that limits usage of the available hosting capacity to the worst-case hour of the year. Future use of Limited Generation Profiles (LGPs)[129] should increase the utilization of available hosting capacity by allowing DERs to export more power during certain hours of the year. That increase will be driven by the LGP work being done in the Rule 21 Proceeding (R 17-07-007). However, customers do not currently always have easy access to the information needed to develop LGPs. **Note: Final details of LGP implementation are still pending an upcoming resolution.**

The amount of additional generation capacity that can be hosted by the distribution system varies throughout the year. Generation ICA employs power flow analyses to determine the amount of

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[126] Administrative Law Judge's Ruling addressing PG&E, SCE, and SDG&E's claims for confidential treatment and redaction of distribution system planning data ordered by decisions 17-09-026 and 18-02-004, R.14-08-013, July 24, 2018.

[127] Decision 97-10-031 (Opinion Regarding the Customer Information Database Workshop Report), R.94-04-031 (Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation) & Investigation 94-04-032 (Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation), October 9, 1997.

[128] Decision 14-05-016 adopting rules to provide access to energy usage and usage-related data while protecting privacy of personal data, R.08-12-009, May 5, 2014.

[129] Limited Generation Profiles are being developed per Resolutions E-5211 and E-5230 which were both a result of D.20-09-035 in R.17-07-007. These profiles will allow generators and energy storage systems to export more power during some months and/or hours to better utilize existing hosting capacity and streamline the interconnection process. These LGP interconnection agreements could be critical to allowing generators and storage systems to support the grid during peak demand hours, such as late afternoons during the summer months.

additional generation capacity. ICA is performed for 288 hours per year, at two load conditions (10%/90%) per hour (566 total Generation ICA results). To date, attention has been mainly focused on the minimum value from among the 566 ICA results. These minimum values have been presented in data portal map popups and used in Rule 21 Fast Track screens to limit the size of the DER system.

When a single, annual minimum ICA result is used to determine whether the project stays in the Fast Track process, opportunity is lost to interconnect larger amounts of power that could export power at times when the distribution system could accommodate it and may critically need it. Installing a generator sized larger than the annual minimum ICA result and then limiting its output to reflect the variation in grid conditions through the year can allow the total power export to be maximized while avoiding the need for upgrades at the time of interconnection.

Figure 5-1 below illustrates LGP at a conceptual level for the following four scenarios:

- **Annually**: Currently for projects that wish to stay in Fast Track, the project size (and therefore export limit) is set by the minimum annual hour over the year, in this case in March at 1,270 kW, shown also as a dashed line across all months and hours.
- **Hourly**: The black line depicts the by month and hour ICA-SG (Sta�c Grid) values (24 hours * 12 months = 288 values).
- **Monthly**: The green line shows the monthly minimum ICA-Sta�c Grid (ICA-SG) value, with a 10% buffer added for safety. Given the shown ICA-SG values, this would be the maximum LGP a customer could submit at �me of interconnec�on applica�on. The lowest monthly minimum value of the green line is 1,270 kW in March while the highest monthly maximum is 2,109 kW in September.
- **Monthly by Peak Period**: The dashed orange line shows an alterna�ve that breaks each month into a peak (4-9 PM) and off-peak period. In this case, some months like August could see substan�ally higher exports (2,379 kW) allowed during peak hours vs non-peak hours (1,424 kW.) August is shown as a red box for easy reference.

It should be noted that the figure below is purely conceptual and does not represent the final form of the LGP. The format of the LGP is still being defined and is expected to be voted on by CPUC Commissioners in late 2023 or early 2024.

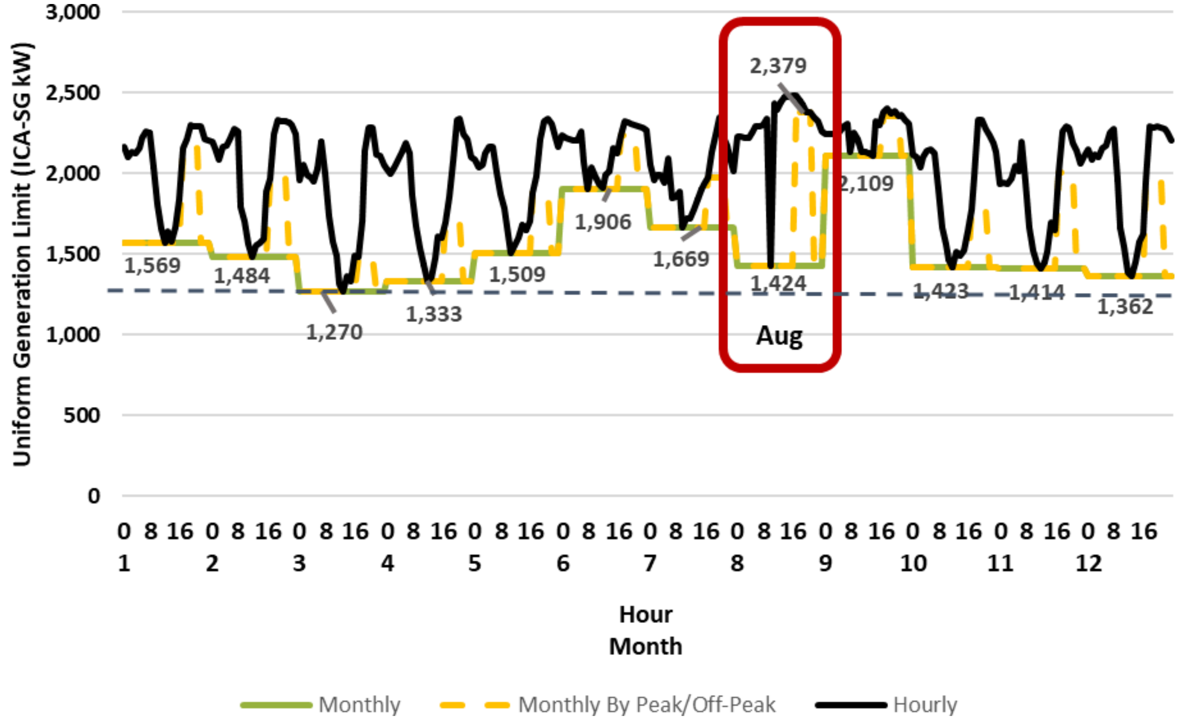

Figure 5-1: Conceptual Illustration of the use of Different Limited Generation Profile Options

As illustrated above, a generator using a limited generation export profile would be able to take advantage of the available ICA-SG hosting capacity as published at the time of interconnection. The LGP option allows the interconnected system to "[exceed] the minimum annual Interconnection Capacity Analysis-Static Grid (ICA-SG) value while remaining below the maximum ICA-SG at any given time." (D.20-09-035 at 119)

Use of LGPs would allow more generation or storage discharge to better utilize hosting capacity during certain hours. To fully realize the benefits of LGPs, the Generation ICA portals will need to provide the right data to customers and properly incorporate these data for calculations. Implementation of generation interconnection arrangements that accommodate LGPs will require several modifications of existing practice as the current Generation ICA is designed to provide a single, annual minimum result, and thus customers do not have easy access to the information needed to develop LGPs.

Use Case: This should aid both **Locating and Siting DERs** and **Streamlining Interconnection** by first enabling more generation (or storage) capacity to be interconnected to the grid, and then making interconnection of those DERs through the LGP an easier process for both developers and utilities.

Responsibility: IOU Issue

Data Portals Key Goal 1 – Enhance Usefulness: This will make the Generation ICA portals more useful for developers and others making use of the LGP option which will allow for better use of existing grid capacity for the interconnection of new generation and storage.

Party Comments:

- Clean Coali�on expressed support for this in their response to Ruling 2 Ques�on 15: "Recommend: 1. Incorporate LGP (with accurate, validated data) into the Rule 21 interconnec�on process."

Commission Action: Commission shall order IOUs to add functionality to the ICA maps enabling customers to download a file containing the subset of Generation ICA results needed to develop an LGP. The file for customers to download should mirror the structure of that which the IOUs propose for the customers to submit in their interconnection applications. The file should be filled in with all the data that is required, and then leave a column open for the customer-generated LGP.

Pre-processing of ICA-SG results shall be performed within the data portal, thus relieving customers of the responsibility for extracting the subset of relevant values from data files containing all Generation ICA results. The CSV files shall include a column containing the relevant ICA-SG results, as well as a column calculated as 90% of each ICA-SG value.

Rationale: Interconnection rules incorporating Limited Generation Profiles (LGPs) are being developed as a result of the Rule 21 proceeding (R.17-07-007). The above action will enable project applicants to easily and accurately create LGP profiles for use in their interconnection applications.

The three IOUs have different plans for supporting LGPs through their ICA data portals. Below, we summarize those plans as communicated in response to data requests issued by the Energy Division.

- **PG&E** Stated that they plan to support LGP in their 2023 ICA Refinements Annual Report: "LGP customers will be able to upload a 288-hour export profile into the PG&E applica�on portal (12 month, 24 hours a month) in CSV format. These profiles will be treated as a separate category of genera�on and used as inputs for ICA calcula�ons. Currently, the requirements have been captured and documented in the ICA refinements project but not implemented yet."[130]
- **SCE** is planning to add func�onality to support LGP customers. SCE envisions the capabili�es below to be implemented by Q3 2025, with approximately 60% confidence in that �meframe.
    - LGP customers must have the ability to provide the IOUs with their proposed LGP values (schedule). While the desired goal is for LGP customers to upload a CSV file along with their interconnec�on request, the file may be provided to the IOU via email as an interim step un�l this func�onality is available.
    - The customer-provided LGP must be stored in a way (most likely a database) that allows it to be referenced by the IOUs' ICA and/or power flow models.
    - When ICA is performed, the customer-provided LGP values must be associated with a generator within the power flow model, which will vary the modeled generator's output on an hourly basis.
    - Pre-processing of ICA-SG results to provide the LGP values in DRPEP.

- **SDG&E** does not have any firm plans to change its ICA portal to support the LGP Customers but may develop plans for changes once the LGP is finalized. Currently, users can download 576 hour profiles

[130] PG&E 2023 ICA Refinements Annual Report, December 12, 2023

from SDG&E's ICA Data Portal. In addi�on, SDG&E's Interconnec�on Portal can intake a file as **a** atachment to a customer's LGP interconnec�on applica�on. SDG&E does not an�cipate any modifica�ons will be necessary to accommodate LGP interconnec�on requests but has not yet iden�fied all the changes that will be needed to its internal processes and models.[131]

5.4.2. Modify ICA Methodology to Make use of LGP Application Information

Note: This proposal 5.4.2 is related to proposal 5.4.1 ('Modify ICA Maps to Enable Straightforward Customer Creation of Limited Generation Profiles (LGPs)'.) This proposal is focused on IOUs using generation profiles submitted by customers with LGP interconnection applications in their ICA calculations instead of using standard generation profiles (uniform generation or generic PV generation). Proposal 5.4.1 Modify ICA Maps to Enable Straightforward Customer Creation of Limited Generation Profiles (LGPs) is focused on enabling customers to easily create LGP information.

Description of Issue: Future use of Limited Generation Profiles (LGPs) should increase the utilization of available hosting capacity by allowing DERs to export more power during certain hours of the year. It is expected that this will primarily apply to solar paired with storage. However, utilities have differing plans of how to utilize these data in their ICA methodologies.

Use of LGPs would allow more generation or storage discharge hosting capacity during certain hours. To fully realize the benefits of LGPs, the Generation ICA data portals will need to provide the right data to customers and properly incorporate these data for calculations. Implementation of generation interconnection arrangements that accommodate LGPs will require several modifications of existing practices as the current system is designed to use a single, annual minimum ICA result, and thus utilities may not have an automated means of integrating LGPs with ICA and other grid planning tools.

Related Use Cases: By refining available capacity based on LGP applications, this proposal should aid with **DER Siting and Interconnection**.

Responsibility: IOUs

Data Portals Key Goal 1 - Enhance Usefulness: This will make the ICA portals more compatible with data needs of customers making use of the LGP option. This should help make better use of the existing grid capacity for interconnection of new generation and storage.

Proposed Commission Action: Commission should order the utilities to modify their ICA methodologies to incorporate LGPs submitted with interconnection applications when estimating interconnection capacity.

Rationale: Interconnection rules incorporating Limited Generation Profiles (LGPs) are being developed as a result of the Rule 21 proceeding (R.17-07-007). The above action will ensure the ICA maps are updated to reflect accurate hosting capacity. When LGPs get implemented, it is necessary for IOUs to

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[131] Per response to California Public Utility Commission Data Request – ICA Part 2 R.21-06-017 High DER OIR SDG&E Response Date Received: July 26, 2023 Date Responded: August 23, 2023

update their ICA to account for approved systems utilizing LGPs having an effect on available hosting capacity so that prospective applicants receive the most up-to-date ICA information for future projects.

5.4.3. Create New Report that Includes ICA Results Appended to Current Rule 21 Quarterly Interconnection Report Which Allows for Comparison Between ICA Values and Quarterly Interconnection Timelines Report

Description of Issue: Stakeholders have struggled to understand several aspects of ICA accuracy and how useful the ICA maps are for siting new DERs. Stakeholders lack sufficient information to compare ICA results to outcomes of hosting capacity and mitigation or upgrade needs assessments completed by distribution engineers.

The limiting criterion driving the Generation ICA results is one such piece of information that could help to alleviate this struggle but is not easily accessible to stakeholders. Limiting criterion influences the likelihood of distribution mitigations vs. upgrades which can vary substantially in monetary cost and time. For example, mitigations such as setting changes can be much less costly and time consuming than grid upgrades like new transformers, conductors, or substations. However, stakeholders do not currently have access to the information to estimate the impacts of different limiting criterion on their applications, or a tested methodology to leverage this information to assess the accuracy of the ICA maps for siting new DERs. The ability of Generation ICA results to predict distribution mitigation or upgrade needs for interconnection applications is one possible basis for assessing their accuracy/usefulness. Stakeholders may reasonably expect that interconnection applications for projects sized larger than the ICA hosting capacity may likely necessitate distribution mitigations or upgrades. Conversely, applications submitted for projects smaller than the ICA hosting capacity might be expected to not require distribution mitigations or upgrades. However, an exploration into ICA hosting capacity and mitigation or upgrade concordance conducted by Verdant suggests this is not always the case.

As noted in the recommendation above to clearly indicate limiting criteria in the data portals (5.3.1), interconnection timeline and cost may possibly be associated with the type of ICA limiting criterion. Violations of thermal limits may be associated with larger cost and schedule impacts, as compared to violations of voltage limits (mitigation of which might be accomplished with changes to settings of existing distribution equipment).

Stakeholders currently lack the information necessary to fully assess the relationships described above.

Related Use Cases: By providing information on the accuracy of ICA data portals, this proposal will aid with **DER Siting and Interconnection**. It will also provide the basis to make targeted improvements to better align Generation ICA calculations with DER interconnection.

Responsibility: IOUs

Data Portals Key Goal 1 Increasing Usefulness: Creating this report will provide critical data to assess and support improving the accuracy of the Generation ICA data portals and transparency for stakeholders of how accurately the ICA data portals predict the interconnection process.

Party Comments:

- GPI supported this in their Ruling 2 Comments RE: Ques�ons 10 & 13 and Ques�on 15: "Cri�cal improvements, ordered by importance: 1. Accuracy and ac�onable ICA data 2. Ongoing accuracy of ICA data with regular updates."

Commission Action: Create a new report that appends Generation ICA hosting capacity (kW), limiting criteria as shown in **Error! Reference source not found.** (at the time of interconnection application submittal), and all mitigation or upgrade occurrences to the quarterly Interconnection Timelines reports that track interconnection activities performed by distribution engineers, ordered under Decision 20-09-035 (Figure 5-2). The utilities shall develop guidelines on the portals to help stakeholders understand how different limiting criteria may impact interconnection. This will allow stakeholders to directly assess how well the Generation ICA results predict interconnection and when zero hosting capacities might be more flexible than currently shown on the maps.

Additionally, establish a methodology and process for an ongoing and recurrent analysis comparing ICA results and interconnection results, including issues of safety and reliability, benefits to customers and ratepayers, and contributions to grid reliability. The details of this will need to be worked out based on discussions with the Interconnection and Distribution Engineering team that oversees the Rule 21 proceeding and based on pending resolution of Limited Generation Profiles implementation details. This will also need to include defining what are mitigations, minor upgrades, and major upgrades.

Finally, staff should be allowed the ability to update the report content and methodology over time to ensure it provides meaningful information for stakeholders and policy makers.

Limiting criteria at time of application submission

ICA hosting capacity at the time of application submission

Additional Information

App ID	App Date	Project Size (kW)	ICA Hosting Capacity (kW)	Upgrade or Mitigation	Limiting Criteria
Project 1	1/1/2022	35 kW	0 kW	Minor	Voltage
Project 2	6/2/2022	100 kW	200 kW	No	None
Project 3	3/4/2022	50 kW	50 kW	Major	Thermal

The upgrade or mitigation column should indicate whether an upgrade or mitigation was major, minor, or not needed

Figure 5-2. Example of information to be added to the quarterly Interconnection Timeline reports.

Rationale: Stakeholders have struggled with understanding the ICA accuracy. The IOUs are required to publish quarterly Interconnection Timeline reports per Decision 20-09-035 in proceeding R.17-07-007. This report allows stakeholders to see how long a generation interconnection took and whether certain distribution mitigations or upgrades were necessary to enable the interconnection. Leveraging the Interconnection Timeline reports in conjunction with the ICA data may help to assess how well the Generation ICA data matches the interconnection experience. Combining the Interconnection Timeline reports with information from the Generation ICA (i.e., when interconnection was applied for), provides the best proxy available to assess how well the Generation ICA data matches the interconnection experience in support of accurate and efficient DER siting.

To investigate the potential analysis possible from these data, Verdant performed an interconnection correlation analysis[132] of the quarterly Interconnection Timeline reports, in conjunction with data requests to obtain additional mitigation information not currently reported, that was matched to Generation ICA data.
Table 5-1 presents how the ICA capacity and grid upgrades or mitigations may align or be in concordance. If the ICA capacity is greater than the application kW, no mitigation is expected to accommodate the new generation. Conversely, if the ICA capacity is less than the application kW, an upgrade or other mitigation is expected to accommodate the additional generation.

Table 5-1. Four scenarios outlining the possible results, grouped by whether or not an upgrade or mitigation occurred, for when quarterly Interconnection Timeline report application project size and ICA data portal reported hosting capacity are compared.

	Grid Mitigation or Upgrade	
ICA Hosting Capacity	No	Yes
ICA Capacity > Application kW	**Scenario 1 (Concordant)** Hosting capacity was greater than the proposed interconnection application generation size and no upgrade or mitigation was required, (The ICA **does** correlate with upgrading or mitigating)	**Scenario 3 (Discordant)** Hosting capacity was greater than the proposed interconnection application generation size and an upgrade or mitigation was required, (The ICA **does not** correlate with upgrading or mitigating)
ICA Capacity < Application kW	**Scenario 2 (Concordant)** Hosting capacity was less than the proposed interconnection application generation size and no upgrade or mitigation was required, (The ICA **does not** correlate with upgrading or mitigating)	**Scenario 4 (Concordant)** Hosting capacity was less than the proposed interconnection application generation size and an upgrade or mitigation was required. (The ICA **does** correlate with upgrading or mitigating)

[128] Appendix B: Interconnection correlation analysis: an exploration into the relationship between hosting capacity and need for grid mitigations or upgrades

Results show that only 57 (31%) of the interconnection applications for which the application's project size was larger than the ICA hosting capacity resulted in an upgrade or mitigation. The largest portion of applications (129 out of 277 or 46% of the total) did not necessitate an upgrade or mitigation but had application project sizes larger than grid hosting capacity (Table 5-2 and more in Appendix B). These 129 projects represent 69% of the projects that applied for interconnection where there was insufficient ICA capacity. These results speak to stakeholder misgivings about ICA accuracy and bolster the need for further verification.

Table 5-2: Summary of PG&E application breakdown for generic PV capacity with Operation Flexibility (by count and percent)

ICA Hosting Capacity	Grid Mitigation or Upgrade: No	Grid Mitigation or Upgrade: Yes	Total	
ICA Capacity > Application kW (Unconstrained)	60	31	91	Count
	66%	34%		% within Row
	Scenario 1 - Concordant	Scenario 3 - Discordant		Concordancy
ICA Capacity < Application kW (Constrained)	129	57	186	Count
	69%	31%		% within Row
	Scenario 2 - Discordant	Scenario 4 - Concordant		Concordancy
Total	189	88	277	Count
	68%	32%	100.0%	% of Total

To further support accurate measurement, additional information is required as hosting capacity alone does not determine whether or not an upgrade or mitigation is needed. For example, utilities have said that the discrepancies between insufficient ICA capacity estimates and interconnection upgrades or mitigations is largely due to the capacity constraints being driven by voltage issues that can be resolved by minor configuration or equipment settings changes. Given this information and the results from the Verdant assessment, knowing what the limiting criterion is and understanding the potential impact of that on needed circuit mitigations can help optimally site DERs making use of existing grid capacity, even when the ICA results show zero capacity available.

5.5. Load ICA and Data Portal Improvements

5.5.1. Develop New Reporting Aimed at Understanding the Frequency of Potentially Erroneous Zero Load ICA Values

Description: SCE and SDG&E Load ICA maps have a very high number of circuits showing zero load hosting capacity which undermines stakeholder confidence in the usefulness of these maps. There is reason to believe that these results contain significant false negatives. These potentially false zeros limit the optimal use of the Load ICA maps to identify existing capacity on the grid for new transportation electrification loads or for other types of new or upgraded loads.

A review of SCE and SDG&E Load ICA maps shows most line sections across their service territories as having no capacity for new load during at least one of the 576 hours analyzed. In SDG&E's territory, Load ICA results show that approximately 60% of line sections have zero load capacity while SCE results were 76% in June 2023.

The significant fraction of SCE and SDG&E nodes with no load capacity is viewed by several stakeholders as overly conservative and leads to customers not using the Load ICA for one of its intended use cases: assistance with siting new loads. With such high percentages of line sections showing no available capacity, few if any developers are using these maps to help site EV chargers or other large loads that may have locational flexibility.

Information comparing Load ICA results and IOU Distribution Engineer energization analysis results is needed to definitively confirm the existence (and possible magnitude) of systematic problems with Load ICA accuracy. Unfortunately, development of this type of information is hampered by lack of visibility into details of new load energization projects (e.g., feeder-segment location, details of any grid mitigations).

Related Use Cases: Locating/Siting DERs and new loads; especially those that have some Location Flexibility (e.g., EV chargers, large energy storage, and maybe cannabis cultivation and data centers)

Responsibility: Regulatory

Data Portals Key Goal 1 Enhance Usefulness: Creating this report will provide critical data to assess and eventually improve the accuracy of the Load ICA results on the data portals. This report will provide transparency for stakeholders of how accurately the ICA results predict the energization process for transportation electrification.

Party Comments:

- IREC supported this in their Ruling 2 Comments RE: Ques�on 12: “While similar considera�ons also apply for applicants seeking to develop electric vehicle charging infrastructure, there are also a variety of other factors in that space that impact the relevance of ICA results that show litle or no hos�ng capacity. The most significant factor at this point is that developers can have essen�ally no confidence in the Load ICA results, par�cularly in SCE and SDG&E’s territory.” IREC also included this in their Ruling 2 Comment RE: Ques�on 11: “In **SDG&E’s territory, the ICA indicates that 110,871 nodes, or 70% of the nodes on their system, have zero capacity** for new load during at least one of the 576 hours analyzed. Even more drama�cally, in **SCE’s territory, the ICA results show that 1,065,364, or 83% of their nodes, have zero capacity** for new load. “
- Clean Coali�on also showed support in their Ruling 2 Comment RE: Ques�on 16: “Load ICA data is not useful because it is inaccurate and lacks granularity.”

Commission Action: Commission should authorize, as appropriate, the High DER and CPUC DRIVE teams to coordinate the addition of data collection fields to the existing EV Infrastructure Data Collection Template[133] and submit the data within the IOUs’ annual EV Cost and Load Report[134]. The new fields will

[133] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/transportation-electrification/copy-of-ev-infrastructure-rules-data-collection-template.xlsx

[134] Pursuant to D.16-06-011, the three large IOUs jointly file the annual EV Cost and Load Report to examine EV customer charging behavior and service and distribution system upgrade costs related to EV load. This report illustrates the costs of infrastructure installed through the IOUs’ EV charging programs, and infrastructure Installed through their Electric Rule 15 and 16, and beginning in 2023, the EV Infrastructure Rules.

collect information needed to assess the accuracy of the Load ICA for customers requesting service through the IOUs' EV Infrastructure Rule. New fields are expected to include:

- Feeder name
- Line segment ID
- Load ICA results when the EV Infrastructure Rule applica�on was submited
- For SCE, the Reserve Load Capacity (a new feature that was recently added by SCE) for when the EV Infrastructure Rule applica�on was submited
- When available, the Forecast Load ICA results when the EV Infrastructure Rule applica�on was submited
- The limi�ng criterion for the above results
- Mi�ga�ons or upgrades taken to enable energiza�on

Staff should annually review these reports and, as appropriate, propose or recommend additional targeted actions to expand the report and order the utilities to reduce potentially false negatives based on the information in these reports.

Rationale: PG&E has significantly reduced the number of line sections that show no available capacity from 65% in February 2018 to only 25% in June 2023 (Figure 5-3). The reduction in PG&E circuits with no additional load capacity was due primarily to Load ICA modifications[135]:

- "Decreased the lower limit of the Steady State Voltage Criteria from 119 V to 118 V, effective November 16, 2021, as ordered by ALJ's ruling ordering refinements to load integration capacity analysis.[136]
- Developed a spreadsheet according to the Independent Technical Expert (ITE) recommendation, which lists the circuits failed in different study cycles. This tracker will help identify the positive or negative trends related to input data quality and inform the root cause analysis.
- Changed the process to store and call for device settings in ICA platform as outlined previously in its improved data validation plan.
- Reduced the time between load profile updates from a maximum of 12 months to 2 months. PG&E started utilizing a moving 12-month window for load data as of January 10, 2022.

SCE's range of zero load capacity circuits range from 83% to 76% and SDG&E's range from 70% to 60% depending on when data were examined.

[135] PG&E Improved ICA Data Validation Plan, Advice Letter 6212-E, May 28, 2021

[136] Administrative law judge's ruling ordering refinements to load integration capacity analysis, Rulemaking 14-08-013, September 9, 2021.

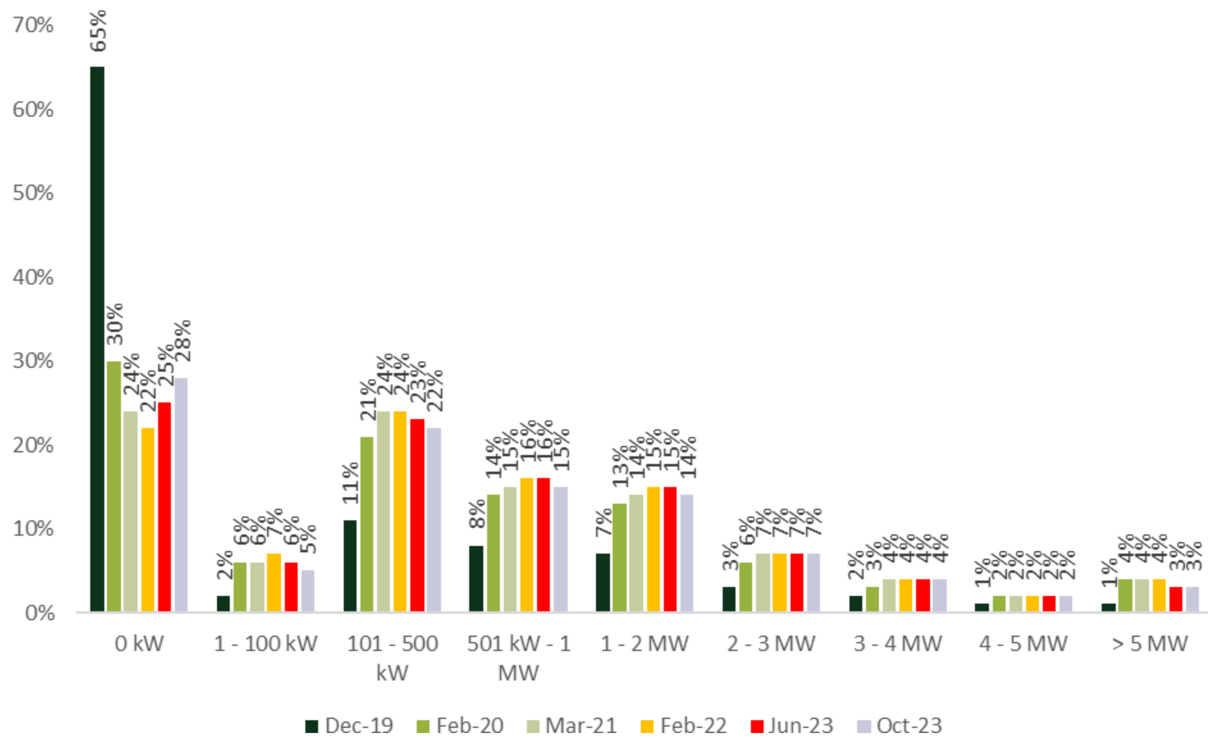


Figure 5-3: PG&E Load ICA Improvements (from PG&E ICA Refinements Report Filed February 28, 2022 and Analysis of June and October 2023 PG&E ICA data)

Although PG&E presented four distinct steps taken to reduce the frequency of erroneous 0 kW Load ICA values, many of these steps do not translate well to the other two utilities. Therefore, based on several discussions with the three IOUs it does not appear feasible for SCE and SDG&E to adopt PG&E's steps directly. This proposal aims to provide a basis to help guide direction to improve their Load ICAs in the future.

To help determine if the higher zero load percentages for SCE and SDG&E were justified, Verdant compared the Load ICA and GNA across each utility. The comparison used GNA results for feeders and Load ICA results for sections. To enable these data with different physical bases to be combined, the Load ICA results were summarized to the feeder level. A feeder with at least one zero-load-hosting-capacity section was classified as a zero-load-hosting-capacity feeder; otherwise, it was classified as a non-zero-load-hosting-capacity feeder. GNA and Load ICA data for a feeder were deemed concordant if neither had any available load hosting capacity, or if both had available load hosting capacity. Figure 5-4 shows the results of this analysis.

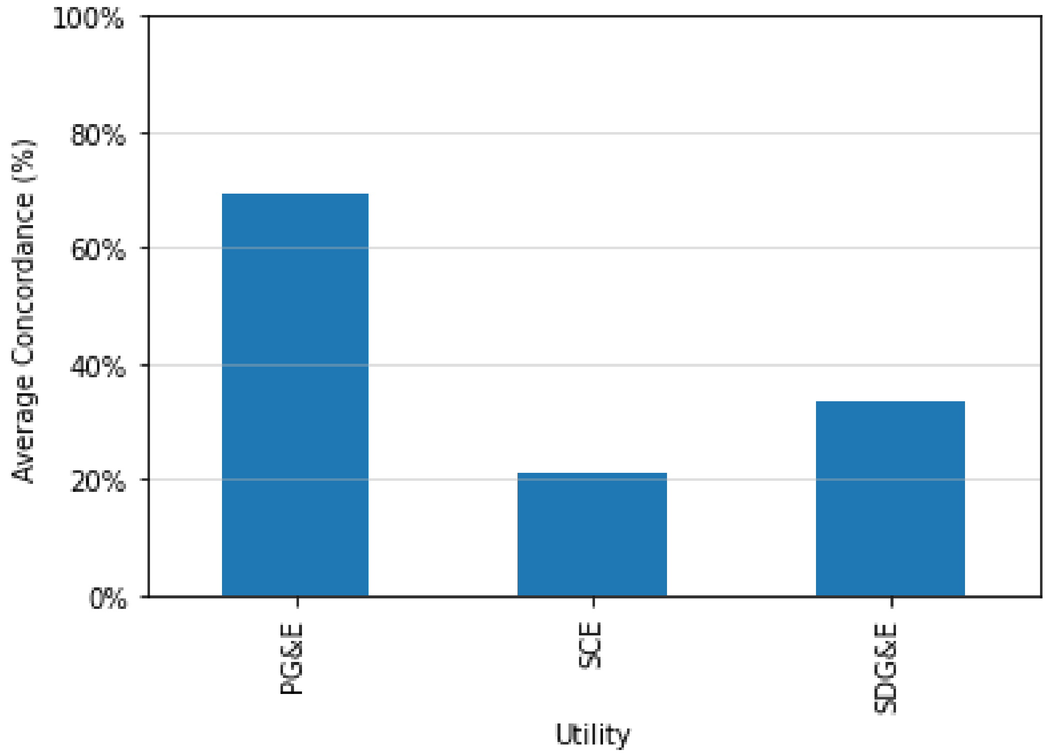


Figure 5-4: Average Agreement or Concordance between Load ICA and GNA/DDOR across the three IOUs

The recent Electrification Impacts Study (EIS) Part 1 may further point to SCE and SDG&E Load ICA results being overly conservative compared to PG&E given that SCE and SDG&E show significantly more circuits with no additional capacity for new loads. The EIS Part 1 found that PG&E's expected upgrade costs to meet future electrification goals were greater than the other utilities, as shown in Figure 5-5. At first glance, PG&E's higher future upgrade costs are inconsistent with SCE and SDG&E having a substantially higher share of line segments with zero load capacity than PG&E.

Figure 6: Total capacity upgrade costs by IOU and scenario, including new substations, transformer banks, feeders, and service transformers *(Source: Kevala)*

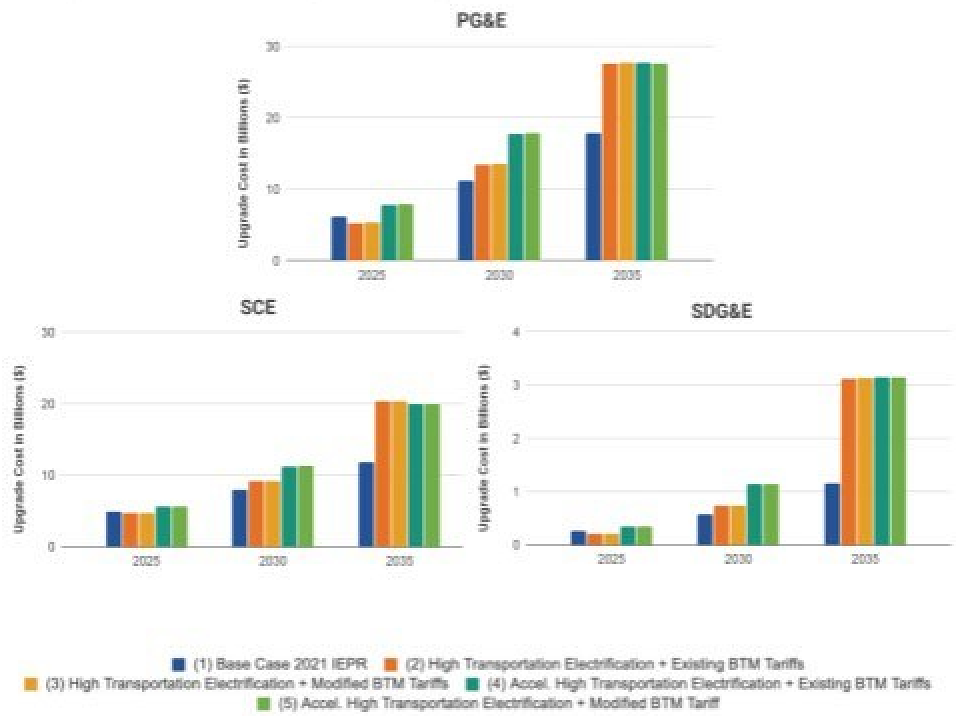


Figure 5-5: Expected Upgrades as Presented in Electrification Impact Study Part 1

The Distribution Grid Electrification Model (DGEM) Study, undertaken by the Public Advocates Office (PAO) at the California Public Utilities Commission, also found that PG&E's expected upgrade costs were higher than the other two utilities, further indicating that PG&E's network may have less capacity than SCE and SDG&E's (Figure 5-6).

		Cost Less 2021 Cost (Millions)			Cost (Millions)		
		2025	2030	2035	2025	2030	2035
Without Secondary	PG&E	$202	$2,434	$5,984	$3,209	$5,449	$9,000
	SCE	$194	$708	$2,186	$608	$1,107	$2,600
	SDG&E	$83	$751	$1,733	$187	$852	$1,834
	Total	$479	$3,893	**$9,904**	$4,004	$7,408	**$13,434**
With Secondary	PG&E	$305	$3,675	$9,037	$4,846	$8,229	$13,590
	SCE	$293	$1,068	$3,301	$919	$1,671	$3,926
	SDG&E	$125	$1,134	$2,618	$282	$1,286	$2,769
	Total	$723	$5,878	**$14,955**	$6,047	$11,186	**$20,286**

The Public Advocates Office

Figure 5-6: PAO DGEM Forecasted Upgrade Needs

Based on the comparison of GNA and ICA maps as well as the EIS & DGEM studies, Verdant believes that SCE's and SDG&E's fraction of zero load capacity circuits should be similar to or lower than PG&E's. PG&E's recent reduction in the share of circuits with no additional load capacity (see Figure 5-3) was due to Load ICA modifications, not grid upgrades or other improvements.

The proposed action will yield information on any differences between Load ICA results and Distribution Engineer energization analysis results. At the very least, this information will help quantify the magnitude of the problem in a rigorous manner, thereby helping to establish priorities for possible next steps. The data from the energization of actual projects may also reveal trends and relationships that could guide development of next steps. Next steps might include detailed review of a sample of projects to identify specific explanations for deviation between Load ICA results and Distribution Engineer energization analysis results. Strengths of the proposal include: (1) speed of implementation, and (2) natural focus on a type of load that is of particular interest (EV charging).

Quantifying the magnitude and nature of the problem is just the first step toward the ultimate goal: Load ICA data sources and analytic methodologies that yield results that are sufficiently well-aligned with Distribution Engineer energization analysis results to allow stakeholders to better utilize existing capacity on the grid for new loads. This should also help avoid long delays in energization for geographically flexible loads like EV charging.

The utilities are currently implementing plans to refine Load ICA. The motivation for refining Load ICA was, in part, due to a lack of concordance between Load ICA and the GNA results that signal a need for projects designed to increase grid capacity. While development of Load ICA refinements will not be completed until 2024-2026[137], beginning the proposed data collection and reporting now will help establish a baseline against which to assess improvements delivered by Load ICA refinements, and assure that additional information about Load ICA accuracy will be available when results of the refined Load ICA first become available.

5.5.2. Incorporate Load ICA Results into Internal IOU Energization Business Processes and Publish Metrics

Description of issue: In a High DER future, IOUs will experience increased volumes of load energization applications (e.g., EV chargers, battery storage). Large increases in the volume of load energization applications have already been reported by IOUs. Timely and effective response to this increased volume will require either additional resources (e.g., distribution engineers), or increased efficiency to process the increased volume.

Load ICA maps are currently a customer facing tool that are not directly used by utilities. However, incorporation of Load ICA results into utilities' load energization processes is an attractive option for

[137] As an interim measure, in 2023 SCE introduced a new source of information about load hosting capacity: circuit reserve load capacity (CRLC). The CRLC is a modified version of the GNA results that are filed each August as part of the DIDF. Modifications contained in the CRLC are designed to capture changes to load hosting capacity that are driven by load growth projects which have submitted a design package to SCE's planning department. While GNA results are filed once per year, CRLC values are updated more frequently to account for new information about load growth projects. The CRLC is different from Load ICA. The CRLC analysis is conducted at the feeder level, whereas Load ICA is performed at the line segment level. The CRLC does not take into account limitations at the circuit node level, which include limitations based on thermal, voltage, and voltage variation. The CRLC values do not account for all limitations on the distribution circuits, which may significantly reduce load hosting capacity.

increasing efficiencies because Load ICA is already being used to calculate load hosting capacity across the IOUs' service areas. Load ICA results are not currently a substitute for the work of Distribution Engineers; however, they can begin to be used by utility staff working with customers who are navigating the energization process. The experience gained with Load ICA results by utility staff and customers is likely to yield information that will contribute to future changes to Load ICA data sources and methodology that will bring Load ICA results into closer alignment with outcomes of energization analyses performed by Distribution Engineers.

Related Use Cases: Incorporating Load ICA Results into Internal IOU Energization Business Processes will create a new use case to leverage Load ICA information.

Responsibility: PG&E

Data Portals Key Goal 1 - Enhance Usefulness: This proposal will leverage the Load ICA data portal for a new use case and streamline energization.

Party Comments:

- "PG&E respec�ully recommends that the Commission consider ordering that "PG&E shall use Load ICA to improve its load energiza�on process to help prepare the grid for a high electrifica�on future. Load ICA shall be used by PG&E's service planning representa�ves to guide customers during this Intake process to help customers beter understand and navigate the energiza�on process. PG&E is authorized to implement this process and tool and record associated costs to the Distribu�on Resources Plan Tools Memorandum Account for future recovery."
- IREC also showed support in their Ruling 2 reply comments, at 4: "IREC is heartened, however, by PG&E's expressed interest in working towards a path wherein the Load ICA can be used to facilitate interconnec�on of new load of all types. The ICA does not have to "replace" the interconnec�on process en�rely for load or genera�on for the ICA to be enormously useful in streamlining and expedi�ng the review process."

Commission Action: Direct PG&E to file a Tier 2 Advice Letter detailing the implementation plan for this new energization use case.[138] The Advice Letter, due within 60 days of a Decision order, shall include:

1. Descrip�on and quan�fica�on of expected benefits and costs for the use case and a �meline of those benefits and costs
2. Descrip�on of a data repor�ng plan that will support monitoring of actual benefits

Note:

A conditional relationship exists between these proposed Commission actions and those presented above in Section 5.5.1 ('Develop New Reporting Aimed at Understanding the Frequency of Potentially Erroneous Zero Load ICA Values'). If the proposal of Section 5.5.1 is not adopted, then its reporting

[138] On October 10, 2023, PG&E communicated its current plans for filing a motion requesting authorization to use the Distribution Resources Plan Tools Memorandum Account to record costs associated with updating its DPP modeling tools to include use of Load ICA for load interconnection in addition to DER siting to improve the overall load energization process. Commission action for the new Load ICA use case will likely need to account for such a motion.

elements may be moved to this proposal by adding the following requirement for the Advice Letter: “Description of a data reporting plan that will provide information necessary to measure differences between Load ICA results and Distribution Engineer energization analysis results”.

Rationale:

If the ICA data can be used to increase efficiency of the load energization process, then the need for additional staff will be mitigated even while new-service application volume increases. As IOU distribution engineers gain hands-on experience with Load ICA, new opportunities for improving Load ICA may arise.

Per PG&E’s response to a data request: “PG&E expects this integration will reduce PG&E’s time to analyze energization requests from 30 days to 20 days by significantly reducing distribution engineer review time and enabling other efficiencies. This integration will also speed up or potentially eliminate the Pre-Assessment step. Additionally, this integration will accelerate the back and forth with new-load customers by allowing both the utility and customer to see the same data at the same time.”

PG&E currently offers an optional “pre-application” project assessment service to commercial EV supply equipment (EV charging or EVSE) customers. The number of EV applications is exponentially growing (more than 600 last year and 1000 anticipated this year) requiring the scaling up of this service. Additionally, PG&E is proposing to expand this optional pre-application service to all customers. As PG&E receives ~100,000 applications a year (and increasing), these services may not be possible without implementing the ”load energization process” Load ICA use case.

CPUC cannot yet verify the above rationale, but if successful, this should allow PG&E to continue to provide pre-assessment services even as its EV energization requests continue to grow.

The pre-application project assessment will be an additional benefit to this proposal. Currently, a significant fraction of PG&E energization applicants cancels their orders prior to the design phase. Adding pre-application screening for these applicants could significantly reduce PG&E staff workload and allow PG&E staff to focus on more viable energization projects.

6. Appendices

6.1 Appendix A Additional ICA Usability and Data Portal Improvements

Description: Each of the utilities has a slightly different implementation of their data portals. This forces stakeholders to learn differing terminology and processes to use each of the four different portals (PG&E has separate ICA and GNA/DDOR portals). This can be a barrier for all use cases, especially for occasional users. Additionally, the data available for download varies by IOU and the process to download varies between the IOUs.

A streamlined and more-uniform user experience will help stakeholders make better use of available data. In addition, making more data available for download will assist 'power users' and reduce utility burden in responding to data requests. For example, SCE implemented their enhanced downloads as a direct result of the data request by UC Davis for a recent study.

Sub Proposal:

6.1.1. Present DIDF & ICA Data on One Map

Key Goals 1 and 2 - Enhance Usefulness and improve design (or usability): Presenting DIDF and ICA data on one map improves user experience and makes the totality of data more digestible.

Proposed Commission Action: PG&E should include DIDF & ICA layers within a single map.

Responsibility: PG&E

Rationale: PG&E's data portals are setup to have ICA results accessible in one map, while LNBA, GNA, and DDOR results are accessible in a separate map with a different login. The current PG&E setup requires users to look at two different maps to acquire all information rather than click between layers on one map. This current setup does not seem to align with the Commission's orders to "…develop a central DRP data access portal, by which users can click between tabs to view ICA, LNBA, GNA, and DDOR data on the circuit map…"[139] The current setup:

1. Is �me consuming,

   C. Requires users to be aware that the maps are separate and that both exist, and

   D. Makes it difficult to fully digest key pieces of informa�on and u�lize the data portal to its full poten�al.

Users of the PG&E data portals (e.g., CESA, Tesla, and workshop attendees via Slido) have expressed this exact sentiment and a myriad of complaints around the usability of PG&E's two-map system, lending support to the argument that the recommendation to combine these data portals will improve usability and accessibility.

PG&E has reported that, using its existing portal infrastructure, it could theoretically combine the data from the two maps for an incremental cost of approximately $200k and over approximately 6 months. However, PG&E advises against this course as it may make the portal less usable for stakeholders. Alternatively, PG&E's two portals could be migrated to a single portal with a different infrastructure that

[139] Decision D.2018-02-004 on Track 3 Policy Issues, Sub-Track 1 (Growth Scenarios) and Sub-Track 3 (Distribution Investment and Deferral Process, R.14-08-013, February 8, 2018. OP#21.

would not hinder the user experience. This approach would take approximately 18 months and cost approximately $1.5 million in incremental development costs (ongoing licensing costs excluded) but is reported by PG&E to be expected to provide a superior user experience.[140]

Sub Proposal:

6.1.2. Use Legend Symbols for Only a Single Purpose

Key Goal 2 - Improve Design (or Usability): Implementing unique symbols increases ease of data interpretation for stakeholders.

Proposed Commission Action: SDG&E maps should use individual legend symbols (e.g., red line) for one purpose only (e.g., to denote zero hosting capacity).

Responsibility: SDG&E

Rationale: SDG&E uses red lines to denote both zero hosting capacity and to denote redacted hosting capacity (Figure 6-1). Red lines are also used by SDG&E to denote transmission lines. This potentially causes confusion amongst users as there is a vast difference between zero hosting capacity and redacted hosting capacity (or transmission lines). Visually conflating these disparate information types represents an important missed opportunity for the maps to do what maps are exceptionally good at: visually displaying variation in a way that allows the user to easily assimilate large quantities of meaningful information.

[140] PG&E November 4, 2022, response to CPUC Energy Division October 21, 2022, data request. Questions 1 and 2.

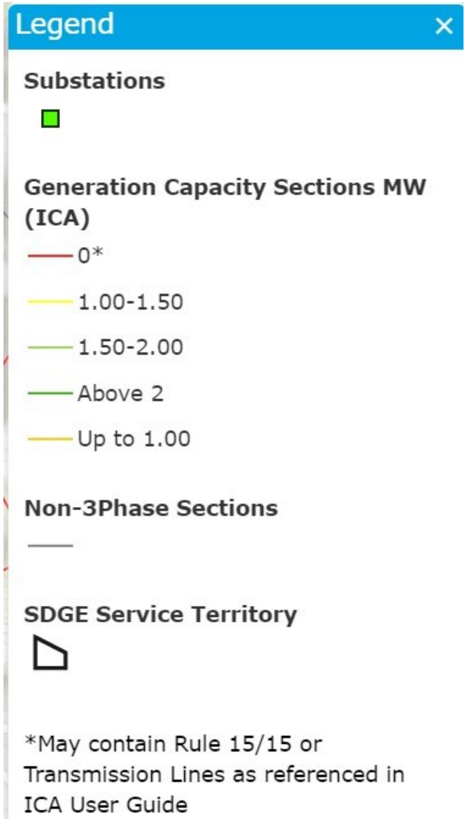


Figure 6-1: SDG&E Line Segment Legends

Sub Proposal:

6.1.3. List Legend Symbols in Consistent Order

Key Goal 2 - Improve Design (or Usability): Appropriately ordering legend symbols increase ease of data interpretation for stakeholders.

Proposed Commission Action: SDG&E should list legend symbols in a meaningful order by placing "Above 0 up to 1.00" between "0*" and "1.00-1.50" and to the legend entry.

Responsibility: SDG&E

Rationale: The legend symbol for SDG&E's "Up to 1.00" is at the bottom of the list of symbols (Figure 6-2). It would be natural for users of the map to expect to find legend symbols in a meaningful order. Listing them in an unmeaningful order diminishes user friendliness. Resolution of this problem should be trivial.

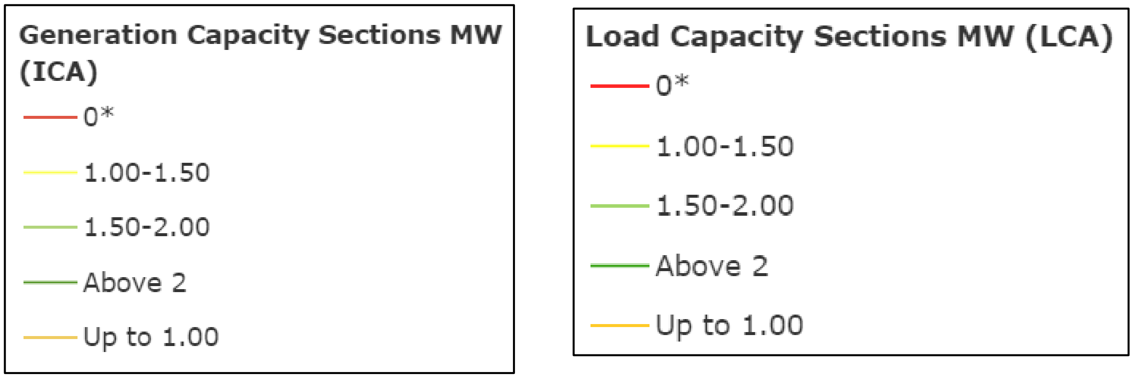


Figure 6-2: SDG&E Legends for ICA MW

Sub Proposal:

6.1.4. Adopt Consistent Acronyms and Terminology Across IOUs for the Most Critical Data Elements

Key Goal 2 - Improve Design (or Usability): Applying uniformity for ICA maps increases legibility for stakeholders and regulators.

Proposed Commission Action: All three IOUs shall adopt the following acronyms, terminology, and variable names (Table 6-1) to use within ICA map popups presenting ICA results, and API CSV data files containing ICA results.

Table 6-1 :Proposed terminology alignment for ICA Map Popups and API CSV files.

ICA Map Popups Presenting ICA Results	API CSV Data Files Containing ICA Results
Uniform Load Integration Capacity	ICA_UNIFORM_LOAD_*W
Uniform Generation OpFlex Integration Capacity	ICA_UNIFORM_GENERATION_OPFLEX_*W
Generic PV Generation OpFlex Integration Capacity	ICA_GENERIC_PV_GENERATION_OPFLEX_*W
Uniform Generation No OpFlex Integration Capacity	ICA_UNIFORM_GENERATION_NO_OPFLEX_*W
Generic PV Generation No OpFlex Integration Capacity	ICA_GENERIC_PV_GENERATION_NO_OPFLEX_*W

**Note: Include units in ICA results data file variable names (replace "*" with "K" or "M" in above)*

Responsibility: PG&E, SDG&E, SCE

Rationale: Each IOU uses their own acronyms and terminology for the same terms and thus direct term matching between IOUs is not always possible. This lack of shared language and industry defined terms is a barrier to effectively utilizing the maps, accessing and utilizing the data, and discussing the results in meaningful, understandable ways.

Per Decision D.17-09-026, “The IOUs shall continue to standardize a common mapping structure[141]”. Using consistent formats and tools between data portals is integral to accomplishing this goal. As acronyms and terminology are key tools to understand the data in the maps, having consistency across portals will be important for the data portals’ success and usability. Stakeholders have voiced concern around current clarity and consistency of these features for both the maps and the downloadable data (esVolta, PCE, Tesla, etc.). Variation exhibited between the three IOUs in their ICA map popups containing ICA results is illustrated in Table 6-2 below.

Table 6-2 : Example of the variation exhibited between the three IOUs for their ICA map popups.

PG&E	SCE	SDG&E
Load Hosting Capacity	Uniform Load Integration Capacity	Uniform Load Integration Capacity
Generation Hosting Capacity	Uniform Generation Operational Flexibility Integration Capacity	Uniform Generation With Operation flexibility (ICAWOF)
Generic PV Hosting Capacity	Photovoltaic Operational Flexibility Integration Capacity	Solar photovoltaic With Operation Flexibility (ICAWOF)
Generation Hosting Capacity w/out OpFlex	Uniform Generation Static Grid Integration Capacity	Uniform Generation NO Operation flexibility (ICAWNOF)
Generic PV Hosting Capacity w/out OpFlex	Photovoltaic Static Grid Integration Capacity	Solar photovoltaic NO Operation flexibility (ICAWNOF)

The standardized terms presented above should follow several guidelines to obtain consistency:

- Use the term "Integra�on Capacity" instead of "Hos�ng Capacity"
- Include a term describing shape ("Uniform", "Generic PV")
- Include the term "Load" or "Genera�on", as appropriate
- Use the terms "OpFlex" and "No OpFlex" to dis�nguish between those two bases
- Use the term "PV" instead of "Photovoltaic" or "Solar photovoltaic"

Currently, all three data portals have included in their user guide how their terminology aligns to other IOUs’ terminology. Using this section to instead define converged upon terms and acronyms would more fully align to a ‘standardized mapping structure’ and increase the usability of the data portals for a wider range of stakeholders.

Sub Proposal:

6.1.5. Build Out Text and Image Explanations in User Guides and Facilitate Easier Navigation Using Hyperlinks to Augment Guide Digestibility

Key Goal 2 - Improve Design (or Usability): Increasing user guide thoroughness makes the guide easier for stakeholders to use.

Proposed Commission Action: The following sections break down proposed actions for each IOU.

Responsibility: PG&E, SDG&E, SCE

Recommendation for PG&E: User guide organizational structure should follow a logical, explanatory flow similar to SDG&E and SCE’s user guides and the user guide should include the following areas to enhance usability of the map:

[141] Decision D.17-09-026 on Track 1 Demonstration Projects A (Integration Capacity Analysis) and B (Locational Net Benefits Analysis), R.14-08-013, September 28, 2017.

i. Section that includes document change history, purpose, table of acronyms, access, technical support, general overview, and any other information necessary to understand the foundations of the maps.

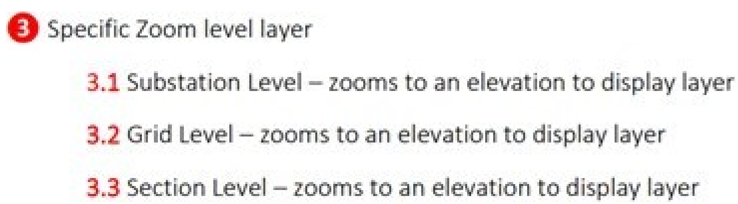
ii. Details about the interactive map including: map navigation, details about icons and functions, elevation map display, legend details, and a general layer list.

iii. Detailed section that covers each map layer extensively, providing both text and image explanations to facilitate utility of the map (if the layer appears in any capacity on the map, it should be clearly explained in this section).

iv. Data download section: any means by which data can be obtained from the map should be clearly explained and outlined in this section.

When creating these sections, ensure that explanatory images are included whenever possible and detailed and mindfully sized with additional shapes, arrows, or other ways to convey critical information to illustrate key components of the maps or directions on how to use specific features. If certain parts of the image are necessary to convey information, these aspects should be clearly indicated in the image in some way that makes it immediately obvious to the viewer. The images alone should be able to communicate key steps and features but should always be paired with explicit text that supports the image and the process or feature it is demonstrating to support effective utilization of the maps by all users. Sections should be hyperlinked in a table of contents at the start of the user guide. It should be easy for readers to differentiate each section and navigate between sections while using the guide.

Recommendation for SDG&E: Adding hyperlinks to additional portions of the user guides so sections can speak to each other would augment usability and understanding of the maps (example: pg. 7 adding hyperlinks to 3.1 : 3.3 that take the user to each specific zoom level layer where they can read more about that layer, Figure 6-3).



3 Specific Zoom level layer

3.1 Substation Level – zooms to an elevation to display layer

3.2 Grid Level – zooms to an elevation to display layer

3.3 Section Level – zooms to an elevation to display layer

Figure 6-3: Screenshot showing SDG&E's map navigation portion of the ICA user guide (page 7).

Recommendation for all three IOUs: User guides should detail the assumptions made about the models used to create the maps.

Rationale: User guides are critical to the success and proper utilization of the data portals. Providing high quality explanations that serve all users regardless of software experience levels or interconnection data familiarity is integral to ensuring that the data portals are effective. Key stakeholders recommended to increase the availability of educational materials, like user guides, that can make the data portals easier to use for stakeholders and the public alike. Mindful and accessible user guides with transparency around the model assumptions used to create the maps are a powerful first step towards enhanced usability of the data portals, regardless of reason for using them (i.e., corporation vs. public).

PG&E: Current user guides (ICA & DIDF) are limited in explanations of data portal terms, map usage, and user guide navigation features. Both PG&E user guides rely heavily on large text blocks for explanation rather than a combination of text and images to facilitate deeper understanding and usability of the data portals and the information they are conveying. Instructions for using the maps are general rather than providing specific step-by-step instructions as is the case for both SCE and SDG&E's user guides. Additionally, the guides themselves are presented and organized in a way that requires greater responsibility for navigation on the part of the user, rather than guiding the reader and providing easy access to different pieces of information through section color coding and hyperlink utilization.

SDG&E: Current user guides lack hyperlinks that can direct users to specific areas of interest in the user guide. Additionally, certain terminology needs further explanation (e.g., Interactive Map Layers 3.1-3.3 all have the same definition) or to be linked to corresponding sections where users can read the explanation in the section that covers that particular terminology.

PG&E, SDG&E, SCE: Model assumptions for the maps are not currently shared in the user guides.

Sub Proposal:

6.1.6. Increase Prominence of the Placement of User Guides and/or Include at the Map Launch Page

Key Goal 2 - Improve Design (or Usability): Increasing prominence of user guides directs and aids in stakeholder use of ICA data.

Proposed Commission Action: SDG&E and SCE should add a two-part system highlighting user guides so that stakeholders can easily identify their location and utilize them. 1) SCE should create a landing page for map access and include a link to the data portal user guides in the same vicinity that access to maps has been linked. 2) If ESRI provides limitations on where the user guides can be placed and PG&E's example cannot be followed (Figure 6-4b), SDG&E should create a pop up similar to SCE's (Figure 6-4d) that alerts potential stakeholders where the user guides are located. Make sure clear terminology like 'user guide' rather than nebulous 'information' or 'navigation tools' is utilized to avoid confusion.

Responsibility: SDG&E, SCE

Rationale: User guide placement is not intuitive to individuals unfamiliar with mapping interfaces and user guides are not readily available in multiple locations with adequate explanations of what they are used for. PG&E places their 'user guide' download prominently in the top right corner of the map, facilitating ease of access and enhancing the usability of the portals. SCE and SDG&E both have their user guides contained within the 'i' icon of the map. SCE does have a pop-up saying to click on the 'i' for information or support but does not specify that user guide information is embedded within the 'i' icon. SDG&E links the user guides in their registration email with explicit instructions to read them before using the data portals but has no indication that guides can also be found within the 'i' icon on their portal.

In interviews, stakeholders recommended increased educational materials for the data portals and pointed out how 'challenges in comprehension are the greatest points of friction in the full adoption of the data portals'. Clear placement of the user guides with adequate information for using the data portals can relieve these challenges. The first step to utilization of educational materials is ease of accessibility of the materials with the second step being facilitation of buy-in to using them. Being mindful of placement of the user guides, increasing the frequency of users encountering them, and clear messaging around what they are and can be used for can help increase data portal comprehension and usage.

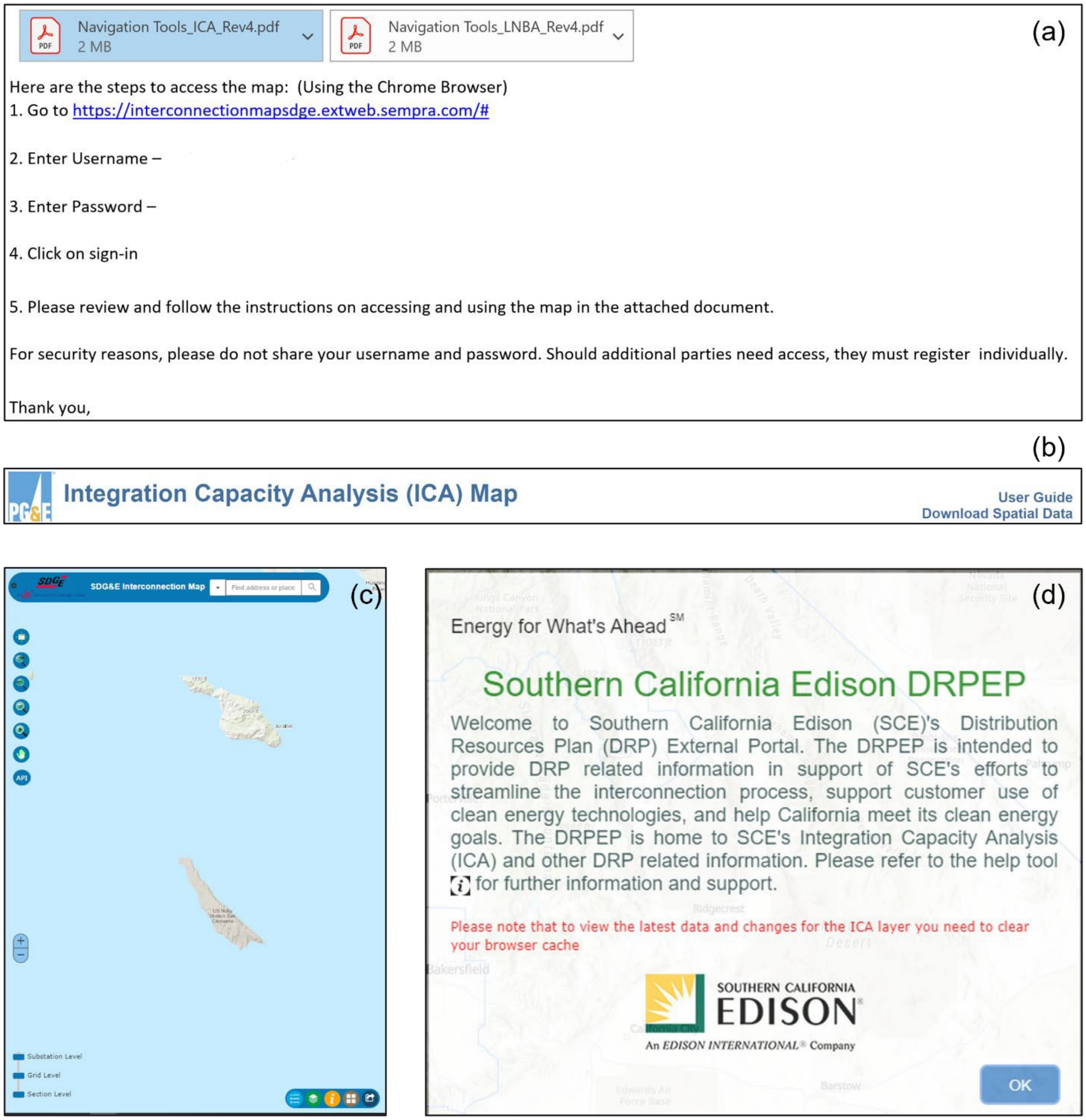


Figure 6-4: Different ways of handling user guide placement and usage. a) SDG&E confirmation email including 'navigation tools' and explicit directions to review the instructions before accessing the maps, b) PG&E's prominent placement and clear usage of the term 'Usage Guide' in the top right portion of the data portal map, c) screenshot showing the 'i' where pdfs of navigation tools are stored for SDG&E, d) SCE's pop up encouraging users to use the 'i' for 'further information and support'.

Sub Proposal:

6.1.7. Provide Functionality to Display Results for all Five (5) ICA Scenarios as Colored Line Segments that Represent Ranges of ICA Results

Key Goal 2 - Improve Design (or Usability): Color-coding data increases data clarity for stakeholders.

Proposed Commission Action: SDG&E and SCE ICA maps should be capable of displaying ICA results as color-coded line sections that represent ranges of ICA result values for all ICA scenarios required in D.17-09-026. ICA scenarios listed in the decision include:

- Uniform generation (with and without operational flexibility)
- Generic PV (with and without operational flexibility)
- Uniform load

In lists of map layers, layers for each ICA scenario should be descriptive, enabling users to distinguish between:

- Generation versus Load ICA
- Uniform generation versus generic PV ICA
- With operational flexibility versus without operational flexibility ICA

Responsibility: SDG&E, SCE

Rationale: The SCE and SDG&E maps display ICA results as colored line segments that represent ranges of ICA result values for only a subset of ICA scenarios. Other types of ICA results cannot be displayed in this manner.

SCE's map displays ICA results as color-coded line sections in the map for Uniform Generation without Operational Flexibility, and Circuit Reserve Load Capacity [the interim substitute for Load ICA until SCE's work on its Load ICA refinements is completed]. While the Dynamic Legend feature in SCE's portal allows users to display results of other ICA scenarios (e.g., Photovoltaic Op Flex) as colored line segments, the user is limited to selecting specific ICA result values (e.g., 0.0031) to associate with a line color. Inability to associate line colors with ranges of values severely limits the usefulness of the Dynamic Legend feature.

SDG&E's map displays ICA results as color-coded line sections in the map only for Load ICA and "Generation Capacity" (it is not readily clear as to whether this is uniform generation with operational flexibility, uniform generation without operational flexibility, generic PV generation with operational flexibility, or generic PV generation without operational flexibility). ICA results available as layers in the SCE and SDG&E maps are shown in Figure 6-5 below.

SCE SDG&E

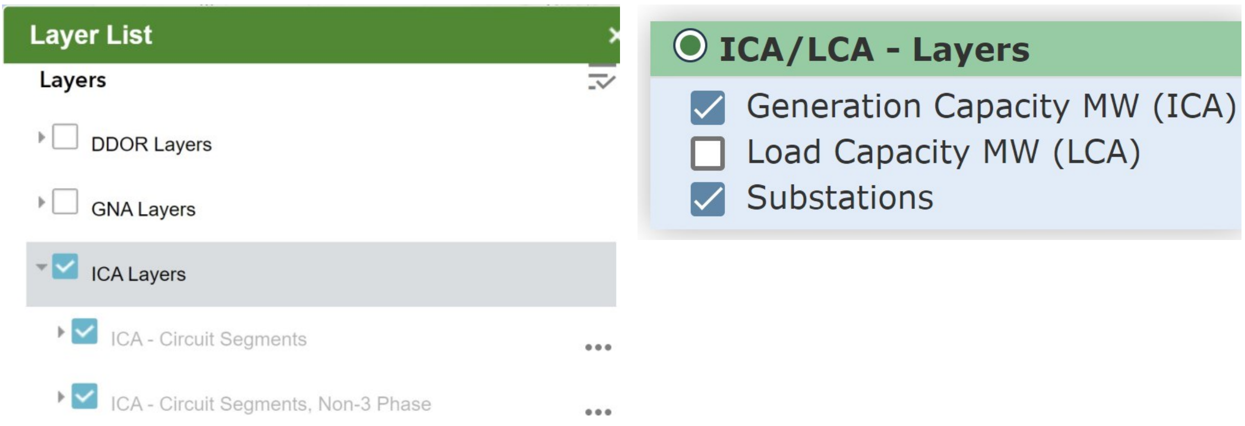


Figure 6-5: ICA Layers in SCE and SDG&E Maps

SDG&E and SCE maps would be more user friendly if they provided functionality similar to PG&E's, including:

i. Enabling display of ICA results as color-coded line sections for all ICA scenarios
ii. Clearly identifying the basis of Generation ICA results (uniform generation versus generic PV, with operational flexibility versus without operational flexibility)

The inability to display all five types of ICA results as color-coded line sections in the map for all scenarios represents a missed opportunity to do exactly what these types of maps are very good at: displaying large quantities of data in a user-friendly manner that enables understanding of variation. All three utilities include numeric ICA results for the complete set of ICA scenarios in their pop-up windows for line sections. However, including ICA results for the complete set of ICA scenarios one line section at a time in pop-up windows is a vastly less effective way of displaying the full range of ICA results. Currently, PG&E's ICA map is the only map capable of displaying ICA results as color-coded line sections for all ICA scenarios. This is accomplished by assigning each of the ICA scenarios to a different layer, as shown in Figure 6-6 below.

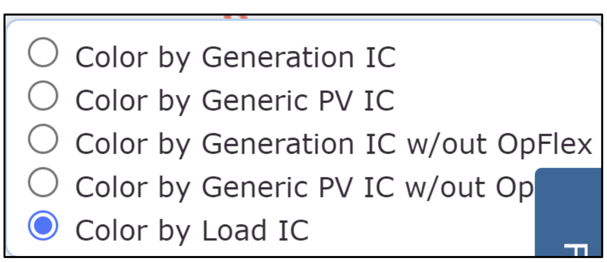


Figure 6-6: ICA Layers in PG&E's ICA Map

Sub Proposal:

6.1.8. Include the Date that the Most Recent ICA Analysis was Completed in Data Files Available for Download both through the Map and via the API

Key Goal 2 - Improve Design (or Usability): Allowing for downloads of more detailed data files increases access to relevant information for stakeholders.

Proposed Commission Action: All three IOUs should include ICA Analysis Date in data files available for download through the map and through the API.

Responsibility: PG&E, SDG&E, SCE

Rationale: Neither SCE nor SDG&E include ICA analysis date in the data files available through the map or through the API. PG&E includes the ICA analysis date in the bulk data geodatabase file available for download by clicking in the map, but not the CSV files that are downloaded one feeder at a time by clicking in the map.

Intervals between ICA analyses may vary from line section to line section, and from utility to utility. The vintage of ICA results is important for several reasons. Customers or developers may desire to know the ICA Analysis Date, as there could be some reasonable expectation that the more recently the ICA was performed, the more closely the results will align with their interconnection/energization experience. Parties interested in monitoring ICA processes/results and responsible for contributing to ICA policy will benefit from understanding trends in ICA results through time, and of observed ICA intervals.

Sub Proposal:

6.1.9. Increase Detail of ICA Results Available in Bulk Download Files

Key Goal 1 – Enhance Usefulness: Allowing for downloads of more detailed data files increases access to relevant information for stakeholders.

Proposed Commission Action: PG&E and SDG&E shall add the option for users to download detailed hourly ICA results in bulk.

Responsibility: PG&E, SDG&E

Rationale: ICA results available in bulk from the PG&E and SDG&E portals contain summary results only. For each line section, an ICA result is provided for:

- Uniform Load
- Uniform Genera�on Without OpFlex
- Uniform Genera�on With OpFlex
- PV Genera�on Without OpFlex
- PV Genera�on With OpFlex

A deeper understanding of the ICA results requires additional detail describing the basis of the above summary result. SCE's DRPEP currently is the only data portal providing users the option to download detailed hourly ICA results in bulk.

ICA is computationally intensive, involving iterative power flow simulation analyses performed individually for several criteria, for 576 circuit loading conditions per line section. For each line section the analysis produces 576 detailed, hourly ICA results for each of the five ICA scenarios. Currently, ICA results available for bulk download are limited to the single ICA result for a line section for which hosting capacity is lowest during the year. While all of the detailed hourly ICA results are available through the maps, they are available in that form only for individual feeders/sections. Stakeholders requiring a broader and deeper understanding of criteria governing summary ICA results have a need for additional detail for all line sections available in bulk. Increased visibility into ICA methodologies and results will enable stakeholders to better contribute to monitoring and modifying ICA in the future. This will likely become much more important when time-varying interconnection such as Limited Generation Profiles are offered.

Sub Proposal:

6.1.10. Provide Load Profile Information Using Units of Power, not Amps

Key Goals 1 and 2 – Enhance Usefulness and Improve Design (or Usability): Providing information in a form that is more easily understood increases stakeholder accessibility.

Proposed Commission Action: Have SCE express aggregate section, circuit, and substation loads in terms of power (MW) in load profile charts and data files available for download.

Responsibility: SCE

Rationale: Aggregate load profile information is expressed as electrical current (amps), creating a missed opportunity to provide grid loading information in a format that would provide valuable context for ICA results (Figure 6-7).

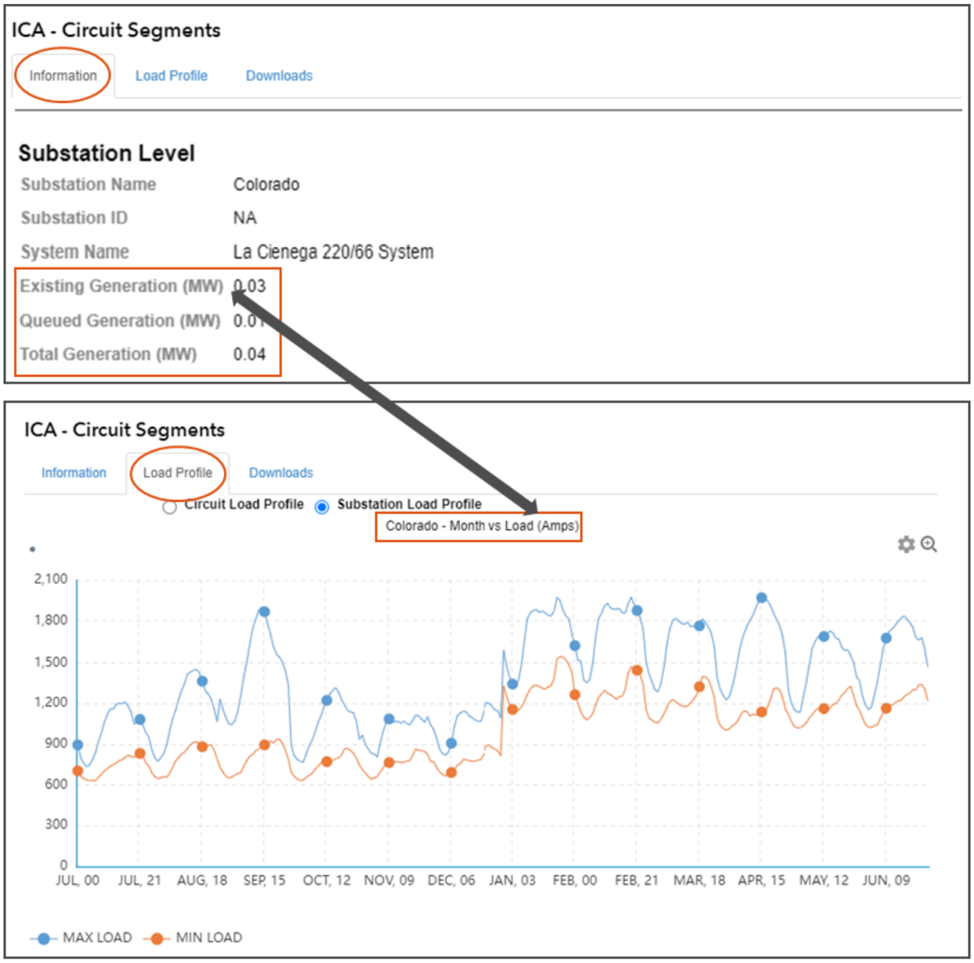


Figure 6-7: Screen capture of load profile for the Colorado Substation for SCE (Oct. 14, 2023). The top panel shows the information tab and generation showed in MW. Bottom panel shows the graphed load profile in amps.

Use of power (MW) in lieu of current (Amps) would relieve map users of needing to find and incorporate line voltage to understand the relationship between line loads and ICA results. Changing the data displayed in the chart and Downloads file would increase standardization among utilities. PG&E ("KW") and SDG&E ("MW") load profile charts contain y-axis labels that indicate that loads expressed as power are being displayed. The Final ICA WG Long-Term Refinements Report concluded that load profiles should be displayed in a standardized format. Changing the data displayed in the chart would increase alignment with New Reform #3 in a June 2021 ALJ Ruling[142]:

a. "New Reform #3: All references to distribution and sub transmission line capacity shall be in megawatts and not amps.
b. Rationale: To ensure consistency in terminology across the IOUs."

The pop-up displayed in SCE's online User Guide contains some indication that loads are expressed as power, and that units are MW. However, the chart title from that user guide suggests loads may be

[142] Administrative Law Judge's Ruling on Recommended Reforms for the Distribution Investment Deferral Framework Process, R.14-08-013, June 21, 2021.

expressed as current and that units are Amps (Figure 6-8). The apparent inconsistencies reduce user friendliness of the map and user guide.

Figure 6-8: Screen capture of SCE's user guide (Oct. 9, 2023) with a title suggesting that results are presented in Amps but data labels showing MW.

Sub Proposal:

6.1.11. Include a Descriptive Y-Axis Label in Load Profile Charts

Key Goals 1 and 2 – Enhance Usefulness and Improve Design (or Usability): Adding additional labeling to charts aids in stakeholder comprehension of provided data.

Proposed Commission Action: Have SCE add a descriptive y-axis label (e.g., "Aggregate Load (MW)") to the Load Profile charts. This recommendation is related to Recommendation 6.1.10, as currently SCE aggregated loads appear in Load Profile charts in units of Amps. Recommendation 6.1.10 would have SCE switch to units of MW.

Responsibility: SCE

Rationale: SCE's load profile charts lack a y-axis label (Figure 6-9).

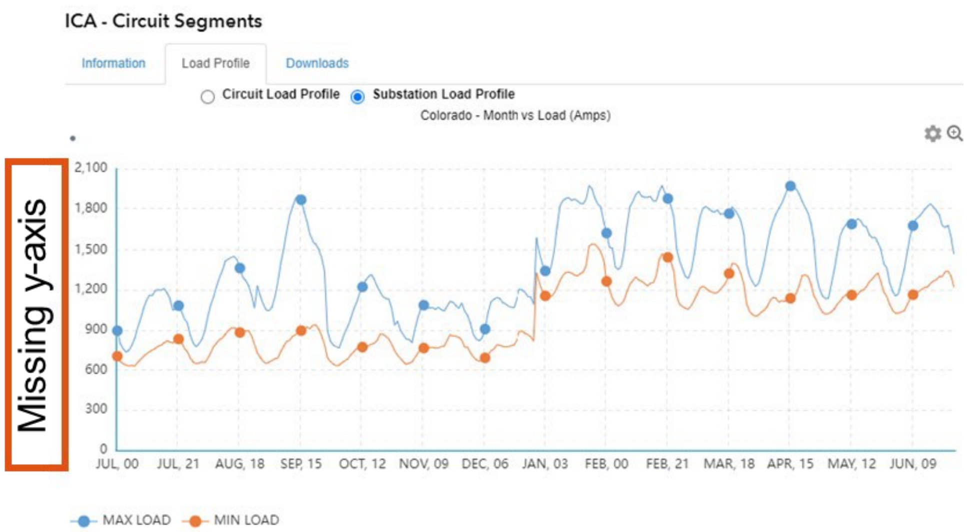


Figure 6-9: Screen capture of load profile for the Colorado Substation for SCE (Oct. 14, 2023). Orange box on left indicates that the y-axis for this graph is missing.

There is variability among utilities in units-of-measure used for load profiles. PG&E and SDG&E load profile charts include a y-axis label, although they are not identical. PG&E's y-axis label is "kW", whereas SDG&E's y-axis label is "MW". Absence of a y-axis label may make it more difficult for users to understand the data, especially if they are working with maps created by multiple utilities. The Final ICA WG Long-Term Refinements Report concluded that load profiles should be displayed in a standardized format and the axis units should be labeled. While it appears that y-axis units may be included in the chart title, it is customary to label y-axis units in the location shown above in the annotated load profile. It should be very easy to add a y-axis label to this chart.

Sub Proposal:

6.1.12. Include a Descriptive X-Axis Label in Load Profile Charts

Key Goals 1 and 2 – Enhance Usefulness Improve Design (or Usability): Adding additional labeling to charts aids in stakeholder comprehension of provided data.

Proposed Commission Action: Have SCE and SDG&E add a descriptive x-axis label to the Load Profile charts.

SCE: Month & Hour of Day (MON, HR)

SDG&E: Month (Results for 24 Hours each Month)

Responsibility: SCE, SDG&E

Rationale: SCE's load profile charts lack an x-axis label. The chart title contains no reference to hour of day, which is a critical aspect of the data in these charts. It would be easy for users to incorrectly assume that the numbers in the x-axis values are day of the month (not hour of the day, Figure 6-10).

Figure 6-10: Screen capture of load profile for the Colorado Substation for SCE (Oct. 14, 2023). Orange box on the bottom indicates that the x-axis label for this graph is missing.

The x-axis label in SDG&E's load profile charts contain no reference to hour of day (Figure 6-11).

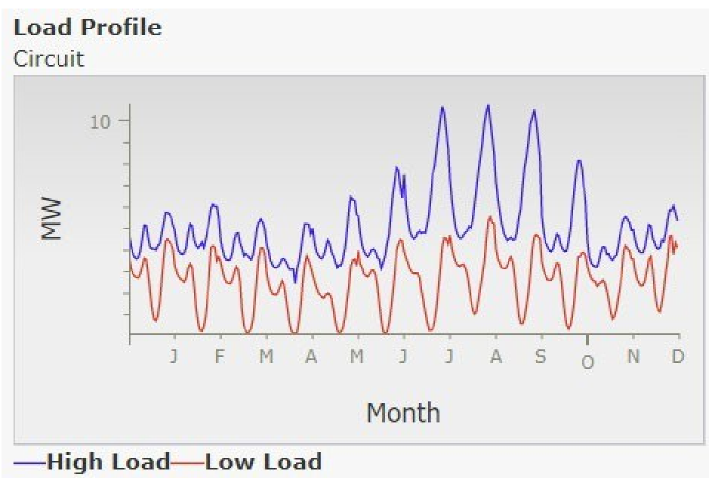


Figure 6-11: SDG&E load profile chart (downloaded March 23, 2023). Hour of day is not mentioned.

The 576-hr load data used for ICA are distinctive in their format and basis. Many users of the maps will not have previously encountered load profiles derived or depicted in this form. This makes it very important that axes be labeled as clearly as possible. Forty-eight data points are depicted for each month: twenty-four data points for each loading scenario (low/high). It is essential that chart annotation contain some reference to hour of day. The manner in which PG&E references hour of day in its load profile charts is shown in Figure 6-12 below. If the software allows, this chart could be improved by using consistently spaced x-axis values (e.g., 01_00, 01_12, 02_00, 02_12,…, 12_12) because having variation in hour values (i.e., 00, 17, 10, 03, 20,…,08) and variation in the number of x-axis values per month makes chart interpretation more difficult.

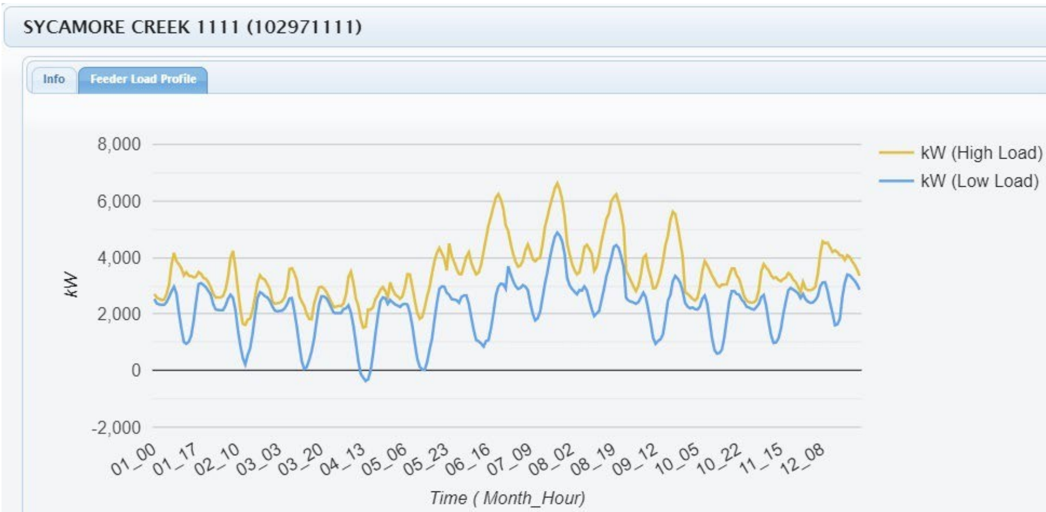


Figure 6-12: PG&E load profile chart showing a detailed x-axis.

Sub Proposal:

6.1.13. Use Descriptive Series Names in Load Profile Charts

Key Goals 1 and 2 – Enhance Usefulness Improve Design (or Usability): Adding additional labeling to figures aids in stakeholder comprehension of provided data.

Proposed Commission Action: Recommended having SCE change series names to "High Load" and "Low Load" (Figure 6-13).

Responsibility: SCE

Rationale: SCE's load profile charts employ series names that aren't strictly correct. The loads depicted in the charts are 90% loads ("High Load") and 10% loads ("Low Load"), not maximum and minimum loads.

Figure 6-13: Screen capture of load profile for the Colorado Substation for SCE (Oct. 14, 2023). Orange box indicates where language is not aligned with recommendation.

It should be very easy to change the series names displayed in this chart. Changing the series names to “High Load” and “Low Load” would increase accuracy and increase standardization among utilities. The Final ICA WG Long-Term Refinements Report concluded that load profiles should be displayed in a standardized format. PG&E and SDG&E load profile charts use series names “High Load” and “Low Load”.

Sub Proposal:

6.1.14. Increase Accuracy of Load Profile Chart Documentation

Key Goals 2 – Improve Design (or Usability): Providing improved documentation increases stakeholder accessibility.

Proposed Commission Action: SCE’s user guide contains instructions for changing the date range that is displayed on the Load Profile graph which states that ‘dragging’ changes the Month-Hour of the results displayed in the pop-up window. It would be more accurate to label this as “7. Month and Hour”, with accompanying text “Drag to change the month and hour for which aggregate load values are displayed in the pop-up”. (Hour 8 during March is shown in Figure 6-14)

Responsibility: SCE

Rationale: SCE’s user guide suggests that dragging in the map will change the date range that is displayed on the graph (a range of 12 months is shown). This description of the dragging function is not accurate. Dragging does not change “the date range that is displayed”.

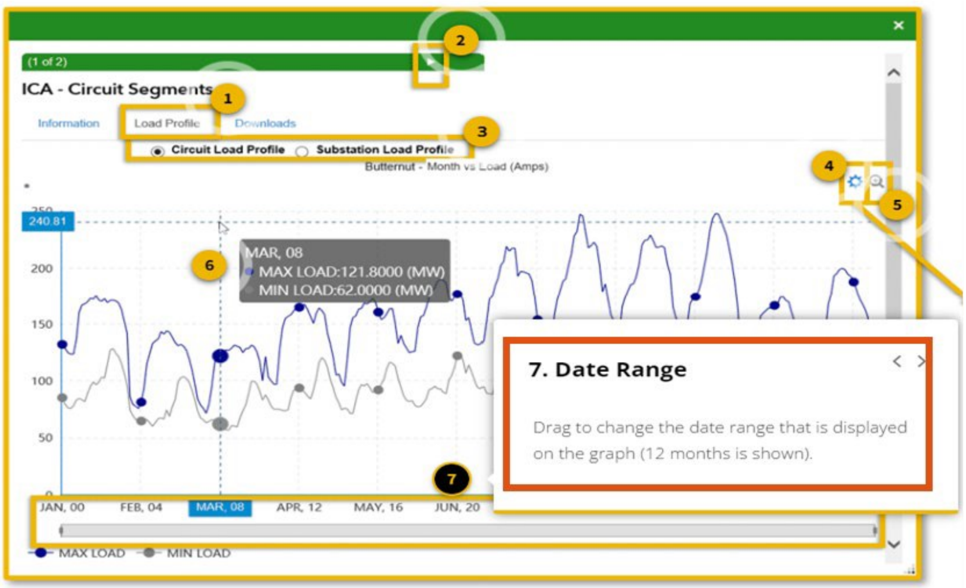


Figure 6-14: Screenshot from SCE's User Guide (Oct. 14, 2023).

The 576-hr load data used for ICA are distinctive in their format and basis. Many users of the maps will not have previously encountered load profiles depicted in this form. This makes it very important that descriptions of the displayed values are clear and accurate.

Sub Proposal:

6.1.15. Offer Bulk Download of all ICA and DIDF Map Data in Multiple File Formats

Key Goal 1 – Enhance Usefulness: Allowing for user to download larger amounts of data aids in their use of ICA maps.

Proposed Commission Action: Require PG&E to enable bulk (i.e., all records) download of ICA and DIDF map data in several formats (e.g., CSV, KML, Shapefile, GeoJSON)

Responsibility: PG&E

Rationale: PG&E's current setup has a bulk download of ICA map data accomplished through a file geodatabase download button in the map ('Download Spatial Data' in the ICA map). While ICA and DIDF map data in other formats (HTML, JSON, KMZ, GeoJSON, PBF) are available through the API, data queries are limited to 1000 records at a time, which may create barriers for stakeholders interested in working with bulk data.

A 2018 decision requires data portals to have Application Programming Interface (API) capability allowing users to access data in a functional format from back-end servers in bulk.[143] Users may access map data in bulk via download of file geodatabases through the map, or through a link between their

[143] Decision D.2018-02-004 on Track 3 Policy Issues, Sub-Track 1 (Growth Scenarios) and Sub-Track 3 (Distribution Investment and Deferral Process, R.14-08-013, February 8, 2018. OP#21.

GIS application and the API. Alternatively, query pages included in the API can be used to access data 1000 records at a time, with results being delivered to a web page. The 1000 records limit also applies to queries performed programmatically (e.g., using Python). While 'functional format' can be loosely interpreted as any format by which the data can be read (i.e., no specific file format), having data formats that are supported by multiple languages and programs will increase the usability of the data by stakeholders. The current setup is limiting, with stakeholders recommending a broader range of downloadable files for increased accessibility to the data.

Both SDG&E and SCE have multiple file types available for API bulk (i.e., all records) download (e.g., CSV, KML, Shapefile, GeoJSON). Free, open source map software (QGIS) can be used to transform file geodatabase contents into other formats (e.g., CSV). Free, open source analysis software (Python) can be used to circumvent the 1000 records limit for programmatic API queries. However, these added layers of complexity create barriers to use of ICA and DIDF data for DER planning, siting, and interconnection.

6.2. Appendix B

6.2.1. Interconnection correlation analysis: an exploration into the relationship between hosting capacity and need for grid mitigations or upgrades

Introduction. Many stakeholders question the accuracy of Generation ICA results (aka generation hosting capacity); in formal comments, formal data requests, and also in a series of stakeholder interviews conducted by Verdant in summer 2022, and during a workshop in July 2022. Resolution of the accuracy questions is complicated by the impossibility of measuring generation hosting capacity directly: it isn't a quantity that can be measured directly with a meter. Consequently, examining ICA results in a vacuum enables an incomplete assessment only. In this paper, a proximate indicator of hosting capacity – grid mitigations or upgrades triggered by interconnection application projects -- is introduced and used to inform ongoing conversations about the accuracy of ICA results.

Background. Analytic methodology and implementation processes for generation integration capacity analysis (Generation ICA) have been evolving for more than five years. Were the goals of ICA fully realized, utility customers and DER developers would have timely access to accurate information about the electric grid's hosting capacity for new generation and load. Armed with this information, developers and other stakeholders could optimize their decisions about the size, location, and timing of DER project development. Such was the vision when California embarked on the ICA development journey.

In June 2021 Quanta Technology completed an assessment of PG&E's ICA data validation plans. The assessment covered data validation, not results validation. As such, it did not cover the actual model building, engineering analysis, and post-processing. The assessment covered factors that could reasonably be expected to influence the accuracy and usefulness of ICA results, but it did not investigate those aspects directly.

In May 2022, IREC asked PG&E to confirm several summaries of percentage of nodes with zero generation hosting capacity. The crux of the issue appeared to be IREC's skepticism of PG&E's results showing a high proportion of segments with zero generation hosting capacity. PG&E's response included: "Yes, this value is within the range that we would expect". At that point in time IREC and PG&E were discussing Generation ICA results in a vacuum, without benefit of any complementary data that might lend credence either to IREC's skepticism or PG&E's confidence in its Generation ICA results.

Verdant and the High DER Consulting team have been working to develop a means to assess the accuracy of the ICA maps. In late 2022, we identified the Quarterly Interconnection Timeline Reporting required of each IOU as a possible source to compare Generation ICA data to. In January 2023 we began analysis focused on a single aspect: the mitigation or upgrade status of each interconnection application. One should expect that a PV generation hosting capacity smaller than an interconnection application project size would necessitate a mitigation or upgrade. Given the complexity of the technical issues involved, we might not expect this to be true in every case. We likely would expect it to be true in many cases.

6.2.2. Data Sources

PG&E

- PG&E Quarterly Interconnection Timeline Reports
    - The report for Q3-2022 was used to create a list of projects that had applied for interconnection during the first nine months of 2022. The report for Q2-2023 was used to assess the development progress of the group of interconnection applications under review. Variables included in the analysis include:
        - 'Key' (project identifier)
        - 'Zip Code'
        - 'Technology Type'
        - 'SizeTotal Proposed Gen'
        - 'Application Received' (date)
        - 'Project Status'
        - 'SP&D[1] Design Start Date'
- PG&E ICA Results
    - Results of ICA were downloaded as geodatabase files from the PG&E ICA data portal. Geodatabase downloads occurred in June 2022 and December 2022. Each of these files contains results of ICAs conducted in numerous months. Variables included in the analysis include:
        - Feeder number
        - Line section number
        - ICA Analysis Date
        - Hosting Capacity: PV with operational flexibility (op flex)
        - Hosting Capacity: PV without operational flexibility (or static grid - SG)
- PG&E Data Request
    - We requested technical constraint and information about mitigations or upgrades that are not recorded in the Quarterly Interconnection reports for 277 projects identified to be in

either the Implementation or Commercial stage of interconnection. The supplemental data file indicated 87 applications for which information concerning a mitigation or upgrade was available. The following variables were utilized in the analysis:
    - Notification (synonymous with NEM Application ID)
    - Equipment (the effort taken to facilitate the mitigation or upgrade)

SDG&E

- SDG&E Quarterly Interconnection Timeline Reports
    - The report for Q3-2022 was used to create a list of projects that had applied for interconnection during the first nine months of 2022. The report for Q2-2023 was used to assess the development progress of the group of interconnection applications under review. Data are contained in five different worksheets. Variables included in the analysis include:
        - 'Project ID', 'APP ID' (project identifier)
        - 'NEM Type', 'INTERCONNECTION TYPE'
        - 'Technology Type', 'TECHNOLOGY TYPE'
        - 'Project Status (Current Phase)', 'DIIS APPLICATION STATUS'
        - 'Size (kW - Net Nameplate Rating)', 'PROJECT SIZE (kW)'
        - 'Interconnection Request Received Date', 'APPLICATION SUBMITTED' (date)
        - 'Preliminary Design Start Date', 'ELECTRICAL DISTRIBUTION UPGRADE YES/NO'
- SDG&E ICA Results
    - Results of ICA were downloaded as a csv file from the SDG&E ICA API. The ICA results download occurred in June 2022. The file contains results of ICAs conducted in numerous months, however the date of ICA is not indicated in the file. Variables included in the analysis include:
        - Circuit name
        - Line segment number
        - Hosting Capacity: PV with operational flexibility (op flex)
        - Hosting Capacity: PV without operational flexibility (or static grid - SG)

6.2.3. Analytic Methodology

PG&E. From among the 5142 records in the Interconnection Timeline report for Q3-2022, 1784 applications satisfying the following criteria were selected:

- 'Application Received' date in 2022
- 'Technology Type': includes "PV"
- 'SizeTotal Proposed Gen' >= 30 kW

These Timeline reports do not include information about the line section associated with an interconnection application. The list of 1784 projects was sent to PG&E along with a request for a lookup table enabling association of a line section with each interconnection application. PG&E provided a lookup table associating interconnection applications with line sections. Line sections were provided for 1251 of the 1784 line sections included in the data request.

Using the lookup table, ICA results were merged into the Interconnection Timeline report for Q2-2023. In numerous instances no ICA result was available for the line section associated with an interconnection application. In other instances, the ICA Analysis Date was not well aligned with the interconnection 'Application Received' date. For line sections with an ICA Analysis Date from both the June and December ICA map datasets, we retained the date prior to and closest to the 'Application Received' date of the interconnection request. ICA Analysis dates more than one year prior to the application received date were excluded. The final list of matched pairs of interconnection applications and ICA results contained 437 projects from among the 1784 originally selected applications PG&E received during the first three quarters of 2022.

The distribution of project development status is detailed in the table, where projects with a SP&D Design Start date were classified as needing distribution mitigations or upgrades.

- No distribution mitigation or upgrade required:
  - Withdrawn: 48
  - Application Review in Progress: 10
  - Study in Progress: 16
  - IA in Progress: 83
  - Implementation: 128
  - Commercial: 119
- Distribution mitigation or upgrade required:
  - Withdrawn: 1
  - Study in Progress: 2
  - Implementation: 26
  - Commercial: 4

Prior to comparing the hosting capacity of the ICA with project size, the dataset was filtered to retain only those projects that had progressed far enough along in the development process for it to have been possible for a mitigation or upgrade's needs assessment to have been completed. Because studies are performed to ascertain mitigation or upgrade's needs, until those studies are completed a project's mitigation or upgrade status cannot be determined. Consequently, the projects with status equal to "Study in Progress" [and all status values preceding it] are excluded. Projects with a status equal to "Withdrawn" are also excluded.

Relatively little information is available for drawing conclusions about the "IA in Progress" status. This status typically follows "Study in Progress" and precedes "Implementation". Most notably, none of the projects for which a mitigation or upgrade need has been identified has a status of "IA in Progress". This may be an indication that mitigations or upgrades are not initiated until the interconnection agreement is complete. We proceed under this working hypothesis and exclude projects for which status is "IA in Progress".

Most of the projects for which a mitigation or upgrade need was identified are at the "Implementation" status. The decision about whether to include this project development status depends in part on the stability of mitigation or upgrade status values when project status is "Implementation". If the mitigation or upgrade status of "Implementation" projects isn't likely to change, then we would lean toward including them. If there's a sizable chance that the mitigation or upgrade status will change before status reaches "Commercial" then we would lean toward excluding them.

Review of the reports indicates that mitigation or upgrade status of “Implementation” projects is not likely to change. For this review, projects advancing from “Implementation” in Q3-2022 to “Commercial” in Q1-2023 were selected. Among these projects there were 222 with a mitigation or upgrade status of “none” in Q3-2023 when project status was “Implementation”. None of these mitigation or upgrade status values was changed in the Q1-2023 report when project status was “Commercial”. These data suggest that the mitigation or upgrade status associated with the project status “Implementation” is unlikely to change. Consequently, these projects were included in the analysis.

The final constrained dataset resulted in 277 applications that were listed as either in the “Implementation” or “Commercial” stage. To ensure that all mitigations or upgrades required for the applications in this finalized dataset were captured prior to analysis, we submitted an additional, supplemental data request containing information about the prevalence of efforts for mitigations or upgrades that may not be recorded in the quarterly interconnection reports.

The composition of the analysis dataset is summarized below:

- Stage
  - No mitigation or upgrade distribution:
    - Implementation: 82
    - Commercial: 107
    - Subtotal: 189
  - Mitigation or upgrade distribution:
    - Implementation: 72
    - Commercial: 16
    - Subtotal: 88
  - Total: 277
- Technology Type
  - FUCE, Solar PV: 1
  - Solar PV: 251
  - Solar PV, Storage: 25
- NEM/Project Type
  - NEM / EXPNEM: 249
  - NEM / NEM Paired Storage: 8
  - NEM / NEMMT: 1
  - NEM / SNEM Paired Storage: 17
  - NEM / VNEM: 2

The general analytical process is outlined in Figure 6-15 below.

0

Quarterly Interconnection Timeline Report

Project 1	1/1/2022	35kW
Project 2	6/2/2022	100 kW

Data Request to match App ID to Line Section

Data Request

1234
5678

0

Quarterly Interconnection Timeline Report
+
Data Request

Add Field

App ID	App Date	Size (kW)	SP&D Design Start Date	Upgrade or Mitigation	Line Section
Project 1	1/1/2022	35kW	3/2/2022	Yes	1234
Project 2	6/2/2022	100kW		No	5678

A date here means an upgrade or mitigation was required.

0

Quarterly Interconnection Timeline Report

Project 1	1/1/2022	35kW	1234
Project 2	6/2/2022	100kW	5678

Combine

ICAAPI

1234	12/1/2021	0kW
5678	4/1/2022	200 kW

0

Clean Data

App ID	App Date	Project Stage	Line Section	Analysis Date	Upgrade or Mitigation	Keep?
Project 1	1/1/2022	Implementation	1234	12/1/2021	Yes	Yes
Project 2	6/2/2022	Commercial	5678	4/1/2022	No	Yes
Project 2	6/2/2022	Commercial	5678	1/1/2022	No	No
Project 3	3/4/2022	Commercial	**4444**			No
Project 4	5/3/2022		3333			No

Too soon in process to keep

Keep closest date

Analysis date too old

0

App ID	Size (kW)	Hosting Capacity	Upgrade or Mitigation	
Project 1	35 kW	0kW	Yes	Scenario 4
Project 2	100 kW	200kW	**No**	Scenario 1
Project 5	700 kW	0kW	No	Scenario 2
Project 7	50 kW	600kW	Yes	Scenario 3

Chi-square Test

Capacity		
ICA Capacity > App kW	60 **Scenario 1**	31 **Scenario 3**
ICA Capacity < App kW	129 Scenario 2	57 Scenario 4

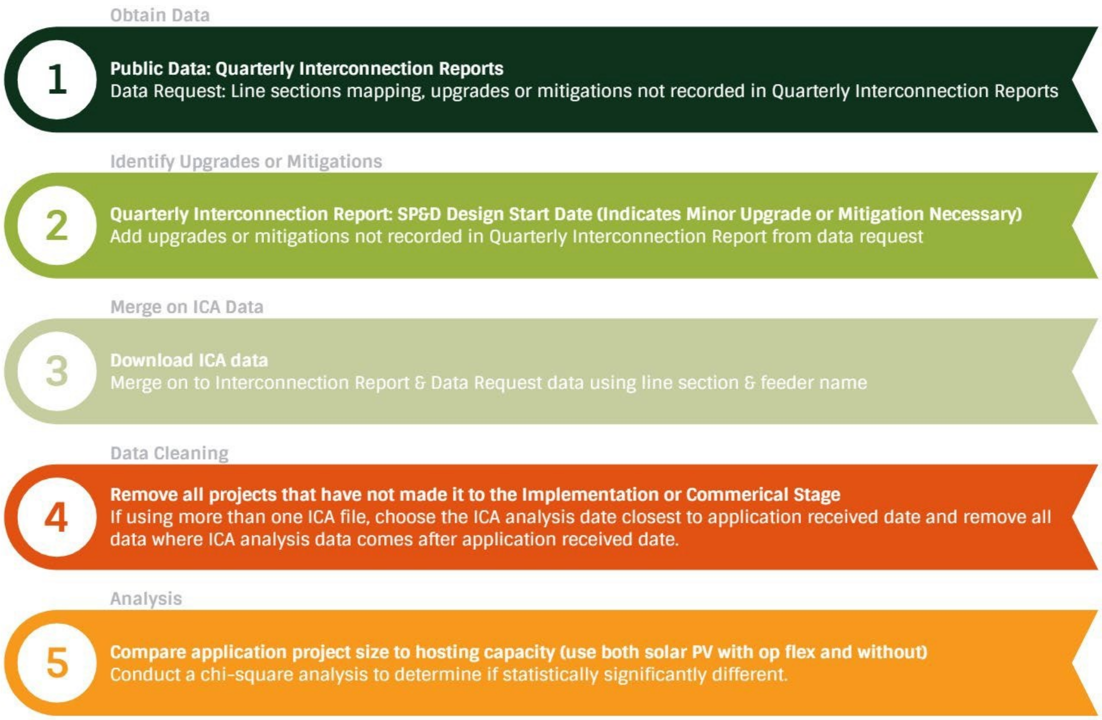


Figure 6-15: Schematic representation of the analytical process. Details of each step are outlined in the text and in the lower portion of the diagram.

SDG&E. From among the 814 records in the Interconnection Timeline report for Q3-2022, 159 applications satisfying the following criteria were selected:

- 'Application Received' and 'Application Completed' date in 2022
- 'Technology Type': includes "PV" or "Battery"
- 'Interconnection Type': "NEM/PRD" or "NEM-ST"

These Timeline reports do not include information about the line section associated with an interconnection application. The list of 159 projects was sent to SDG&E along with a request for a lookup table enabling association of a line section with each interconnection application. SDG&E provided a lookup table associating interconnection applications with line sections. Line sections were provided for 158 of the 159 applications included in the data request.

Using the lookup table, ICA results were merged into the Interconnection Timeline report for Q2-2023. In numerous instances no ICA result was available for the line section associated with an interconnection application. The final list of matched pairs of interconnection applications and ICA results contained 111 projects from among the 159 originally selected applications SDG&E received during the first three quarters of 2022.

The distribution of project development status is detailed in the table, where projects with either a Preliminary Design Start date or an explicit indication of electrical distribution mitigation or upgrade were classified as needing distribution mitigations or upgrades.

- No distribution mitigation or upgrade required:
    - Submitted: 1
    - Approved: 63
    - Pending AHJ Inspection: 47
    - Sub-total: 111
- Distribution mitigation or upgrade required:
    - Sub-total: 0
- Total: 111

Prior to analysis, the dataset was filtered to retain only those projects that had progressed far enough along in the development process for it to have been possible for a mitigation or upgrade's needs assessment to have been completed. The application that had advanced only to the "Submitted" stage was excluded from the analysis.

The composition of the analysis dataset is summarized below:

- No distribution mitigation or upgrade required:
    - Approved: 63
    - Pending AHJ Inspection: 47
    - Sub-total: 110
- Distribution mitigation or upgrade required:
    - Sub-total: 0
- Total: 110

We compared generic PV with operational flexibility (op flex) and generic PV without operational flexibility or static grid - SG) to the size of the proposed generation of the interconnection application. We evaluated four different scenarios and determined the percentage of applications that fell into each category for both generic PV with op flex and SG (Table 6-3).

Table 6-3: Scenarios Comparing Hosting Capacity and Circuit Mitigation or Upgrade

ICA Hosting Capacity	Minor Grid Mitigation or Upgrade	
	No	Yes
ICA Capacity > Application kW	**Scenario 1 (Concordant)** Hosting capacity was greater than the proposed interconnection application generation size and no mitigation or upgrade was required, (The ICA **does** correlate with upgrading or mitigating)	**Scenario 3 (Discordant)** Hosting capacity was greater than the proposed interconnection application generation size and a mitigation or upgrade was required, (The ICA **does not** correlate with upgrading or mitigating)
ICA Capacity < Application kW	**Scenario 2 (Discordant)** Hosting capacity was less than the proposed interconnection application generation size and no mitigation or upgrade was required, (The ICA **does not** correlate with upgrading or mitigating)	**Scenario 4 (Concordant)** Hosting capacity was less than the proposed interconnection application generation size and a mitigation or upgrade was required. (The ICA **does** correlate with upgrading or mitigating)

We analyzed the statistical relationship between hosting capacity on the grid and mitigation or upgrade frequency using Chi-square tests and determined the strength of the relationship using Phi co-efficient.

6.2.4. Results

PG&E. Interconnection applications requiring a mitigation or upgrade in our PG&E dataset comprised 32% of the total applications (Table 6-4 and Table 6-5). Table 6-4 shows the breakdown of PG&E applications that were required to mitigate or upgrade and whether there was adequate ICA hosting capacity for the proposed project using generic PV with op flex. Of the 32% of applications that experienced a mitigation or upgrade, 35% (n = 31, 11% of total applications) of these applications triggered a mitigation or upgrade even though the application's project generation size was smaller than the ICA hosting capacity (Scenario 3; discordant). For the applications that did not require a mitigation or upgrade, 68% (n = 129, 46% of total applications) of these did not trigger a mitigation or upgrade even though the application project size was larger than ICA hosting capacity (Scenario 2; discordant).

There are marked differences between generic PV with op flex and SG for the four different scenarios for mitigation or upgrade frequency and hosting capacity (Table 6-4 and Table 6-5). Table 6-5 shows the four different scenarios (Table 6-3) using SG. For this evaluation, of the 32% of projects requiring a mitigation or upgrade, 66% (n = 58, 21% of total applications) of applications required a mitigation or upgrade despite the hosting capacity of the grid being larger than the proposed project generation size (Scenario 3; discordant) with 37% of those that did not require a mitigation or upgrade (n = 69, 25% of total applications) not triggering a mitigation or upgrade despite the application project generation size being larger than hosting capacity on the grid.

Interconnection applications that did not require a mitigation or upgrade make up most of our dataset (Table 6-4 and Table 6-5) Much like interconnection applications with mitigations or upgrades, there are differences between analyses using generic PV with op flex and SG.

Table 6-4: Summary of PG&E application breakdown for generic PV capacity with operational flexibility (by count and, percent of total)

ICA Hosting Capacity	Minor Grid Mitigation or Upgrade: No	Yes	**Total**	
ICA Capacity > Application kW (Unconstrained)	60	31	91	Count
	22%	11%	33%	% of Total
	66%	34%	100%	% within Row
	32%	35%		% within Column
	Scenario 1 - Concordant	Scenario 3 - Discordant		Concordancy
ICA Capacity < Application kW (Constrained)	129	57	186	Count
	46%	21%	67%	% of Total
	69%	31%	100%	% within Row
	68%	65%		%within Column
	Scenario 2 – Discordant	Scenario 4 - Concordant		Concordancy
Total	189	88	277	Count
	68%	32%	100.0%	% of Total

When including Op Flex, ~2/3 of the interconnection applications exceeded the associated hosting capacity (Scenarios 2 and 4.) However, only a third of applications where the proposed application generation is greater than hosting capacity required a mitigation or upgrade. This suggests that the hosting capacity results are quite conservative, with only 31 percent (57 out of 186) of interconnections requiring a mitigation or upgrade.

Table 6-5: Summary of PG&E application breakdown for generic PV capacity SG (by count and, percent of total)

ICA Hosting Capacity	Minor Grid Mitigation or Upgrade: No	Yes	Total	
ICA Capacity > Application kW (Unconstrained)	120	58	178	Count
	43%	21%	64%	% of Total
	67%	33%	100%	% within Row
	63%	66%		% within Column
	Scenario 1 - Concordant	Scenario 3 - Discordant		Concordancy
ICA Capacity < Application kW (Constrained)	69	30	99	Count
	25%	11%	36%	% of Total
	70%	30%	100%	% within Row
	37%	34%		% within Column
	Scenario 2 – Discordant	Scenario 4 - Concordant		Concordancy
Total	189	88	277	Count
	68%	32%	100.0%	% of Total

The results for Static Grid (SG) show a similar trend as Op Flex, but with about half as many applications (~1/3 of the total) showing a proposed application generation exceeding hosting capacity. Like with Op-Flex, only 30 percent (30 out of 99) of the applications exceeding hosting capacity required a mitigation or upgrade.

We used a chi-square test with Phi co-efficient to determine the statistical relationship and strength of that relationship between hosting capacity (generic PV with op flex and SG) and mitigation or upgrade count. Neither assessment showed significant relationships (Table 6-6 and Table 6-7).

Table 6-6: Mitigation or upgrade count hosting capacity for generic PV with op flex. Alpha = 0.05, Phi co-efficient strength/significance follows the same scheme as Pearson Product Moment Correlation and Spearman co-efficient schemes: 0.1-0.3 small effect, 0.3-0.5 medium, 0.5+

ICA Hosting Capacity	Metric	Grid Mitigation or Upgrade: No	Yes	*p*-value Phi co-efficient
ICA Capacity > Application kW	Count Scenario	60 Scenario 1 – Concordant	31 Scenario 3 – Discordant	*p* = 0.66 -0.03
ICA Capacity < Application kW	Count Scenario	129 Scenario 2 – Discordant	57 Scenario 4 – Concordant	

Table 6-7: Mitigation or upgrade count hosting capacity for generic PV SG. Alpha = 0.05, Phi co-efficient strength/significance follows the same scheme as Pearson Product Moment Correlation and Spearman co-efficient schemes: 0.1-0.3 small effect, 0.3-0.5 medium, 0.5+ l

ICA Hosting Capacity	Metric	Grid Mitigation or Upgrade: No	Grid Mitigation or Upgrade: Yes	*p*-value Phi co-efficient
ICA Capacity > Application kW	Count Scenario	120 Scenario 1 – Concordant	58 Scenario 3 – Discordant	*p* = 0.79 0.02
ICA Capacity < Application kW	Count Scenario	69 Scenario 2 – Discordant	30 Scenario 4 – Concordant	

SDG&E. None of the interconnection applications in our SDG&E dataset was shown to require a mitigation or upgrade in the Q2-2023 Interconnection Timeline report. When including Op Flex, ~90% of the interconnection applications were for projects sized smaller than the associated hosting capacity (Scenarios 2 and 4.) The fact that none of these projects required mitigation or an upgrade suggests that the hosting capacity results were well aligned with the experience of customers. In only a small proportion of cases was hosting capacity smaller than the proposed application. Again, no mitigations or upgrades were needed for these projects, although the ICA result may have created some expectation for such need.

Table 6-8: Summary of SDG&E application breakdown for generic PV capacity with op flex (by count and, percent of total)

ICA Hosting Capacity	**Minor Grid Mitigation or Upgrade** No	Yes	**Total**	
ICA Capacity > Application kW (Unconstrained)	98	0	98	Count
	89%	0%	89%	% of Total
	100%	0%	100%	% within Row
	89%	0%		% within Column
	Scenario 1 - Concordant	Scenario 3 - Discordant		Concordancy
ICA Capacity < Application kW (Constrained)	12	0	12	Count
	11%	0%	11%	% of Total
	100%	0%		% within Row
	11%	0%		% within Column
	Scenario 2 – Discordant	Scenario 4 - Concordant		Concordancy
Total	110	0	110	Count
	100%	0%	100.0%	% of Total

The results for Static Grid (SG) show a similar trend to Op Flex, but with about half as many applications showing a proposed capacity exceeding hosting capacity.

Table 6-9: Summary of SDG&E application breakdown for generic PV capacity SG (by count and, percent of total)

ICA Hosting Capacity	Minor Grid Mitigation or Upgrade: No	Yes	**Total**	
ICA Capacity > Application kW (Unconstrained)	103	0	103	Count
	94%	0%	94%	% of Total
	100%	0%	100%	% within Row
	94%	0%		% within Column
	Scenario 1 - Concordant	Scenario 3 - Discordant		Concordancy
ICA Capacity < Application kW (Constrained)	7	0	7	Count
	6%	0%	6%	% of Total
	100%	0%	100%	% within Row
	6%	0%		% within Column
	Scenario 2 – Discordant	Scenario 4 - Concordant		Concordancy
Total	110	0	110	Count
	100%	0%	100.0%	% of Total

SCE was not included in this analysis because of the ICA data issues that SCE resolved in early 2023, which has not yet given enough time for mitigations and upgrades to be identified so any SCE analysis would be biased.

6.2.5. Discussion

Using PG&E's generic PV with op flex results, we can see that the largest portion of interconnection applications (46%) were those where hosting capacity was smaller than project generation size but did not necessitate a grid mitigation or upgrade: a counter-intuitive result. When considering only the subset of extreme cases with *zero* hosting capacity (n = 177), 71% of interconnection applications did not necessitate a mitigation or upgrade. Among these extreme cases, only, 31% of the applications were for PV systems < 50 kW.

In the case of PV Generation, presumably, this implies that contractors and developers would search the map seeking feeders with ample hosting capacity, to increase chances for a timely and affordable interconnection experience. However, if insufficient hosting capacity is not a meaningful indicator of the need for a mitigation or upgrade, and if hosting capacity is zero for a large portion of segments, it's not clear how the ICA map could possibly be used for the main purpose it was designed. If a contractor or developer used the ICA map for the purpose it was designed, they might be less likely to pursue any DER projects than they would have been had they not tried to use the map.

Conclusions. The ICA map appears ineffective for searching for feeders with ample hosting capacity for additional generation DERs, the main purpose for which it was designed. Anecdotal reports of accuracy and usefulness shortcomings of ICA results are abundant. While such anecdotal reports are valuable, what is needed to continue improving ICA is additional quantitative data describing the usefulness of ICA results.

Recommendations. Additional information about the accuracy and usefulness of ICA results should be developed. This recommendation echoes the recommendation made by Quanta Technology, when they drew a clear distinction between *data validation* and *results validation*, writing: “PG&E would benefit from supplemental results validation process using more advanced analytics and/or rule-based analytics to identify potential issues with ICA results”. Utilities should investigate and share explanations in cases where hosting capacity = 0, yet an interconnection connection application did not trigger a grid mitigation or upgrade. This type of proposed investigation activity is similar in kind to a recent IREC proposal on related questions pertaining to Limited Generation Profiles (which utilize ICA results). One purpose of development of such data is to find out whether deviations from expectations are due to the design/basis of ICA (e.g., excludes capacity constraints of and impacts to the transmission system), or are perhaps due to factors that users of ICA results have little visibility into (e.g., power flow model building, engineering analysis).

[1] Service Planning & Design (SP&D)

6.3. Appendix C ICA-GNA Concordance Status Summary

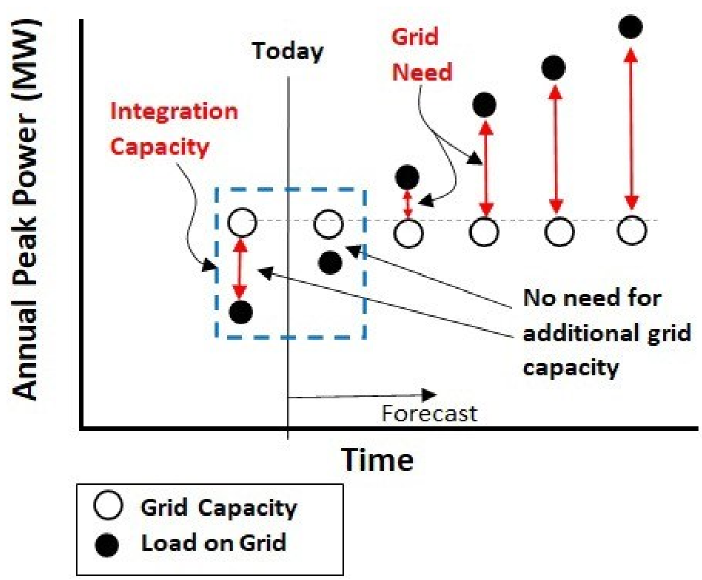
Results of load integration capacity analysis (Load ICA) and GNA reflect some common underlying load and grid topology conditions. An association between these two measures of the grid's ability to accommodate additional load is therefore expected. However, differences in data sources and analysis methods influence the strength of the association. Currently, activity is occurring that is going to change the basis of Load ICA. The motivation for changing the basis of Load ICA was, in part, lack of concordance between Load ICA and GNA results. A complete understanding of changes to Load ICA basis, and the influence of those changes on the Load ICA:GNA relationship, requires an understanding of the starting point. This Load ICA-GNA Concordance Status Summary is intended to help document that current status.

<u>Background</u>

Results of Load ICA are estimates of the amount of new load (i.e., load integration capacity) that could be added to a line segment now, given current grid capacity and current load. Currently, Load ICA is based on the last 12 months of load data, as well as on current grid topography. Using successively larger values of new load size (10 kW increments), iterative power flow analyses are used to assess satisfaction of requirements with respect to several electric grid performance tests. The result of the Load ICA is the largest value of new load size that does not cause failure of any of the tests.

Forecasts of the need for increased grid capacity in future years are produced by GNA. Each year, as part of the distribution planning process, electric load forecasts are developed for each feeder. If the load forecast for a feeder exceeds its capacity, low- or no-cost options (e.g., permanent grid reconfiguration via switches) for utilizing existing grid infrastructure are explorerd.

Load integration capacity and grid need are depicted graphically in the figure below. The blue dashed box highlights a comparison between the load integration capacity and the nearest-term grid need.



Currently, activity is occurring that is going to change the basis of Load ICA. Refinements to Load ICA data sources and analysis methodology were ordered in a September 9, 2021, ALJ ruling. The changes to Load ICA are summarized in the table below, along with the GNA treatment.

		Load ICA	
Element	**GNA**	**Current**	**Future**
Queued load projects	Include	Exclude (except SDG&E)	Include
Planned, known, near-term distribution system mitigations or upgrades	Include	Exclude	Include
Forecasted DER growth	Include	Exclude	Include
Planned network reconfiguration	Include	Exclude	Include
Load forecast	Future years	Past year	Future Year

Proposed plans for Load ICA refinements were filed by the IOUs in early 2022. Rollout of refined Load ICA is expected approximately 2024-2025.

Overview

- Data Sources
- Analytic Methodology
- Results
- Conclusions

Data Sources

Load ICA. Results of Load ICA were downloaded from utility map portals. The dates on which the files were downloaded are listed below. The dates on which Load ICA results were actually calculated vary, but all precede the file download date. Each of these files can be described as having been downloaded in "mid-2023".

PG&E: August 2, 2023
SCE: July 3, 2023
SDG&E: July 3, 2023

GNA. Results of GNA were obtained from Excel files included with annual DIDF filings.

PG&E: DIDF cycle: 2023/2024

	Workbook:	PGE_2023_GNA_Appendix_E_Confidential.xlsx
	Version:	August 15, 2023
	Worksheet:	GNA - Bank & Feeder Capacity
	Column:	Anticipated Need Date
SCE:	DIDF cycle:	2023/2024
	Workbook:	R2106017-2023 SCE GNA_Confidential.xlsx
	Version:	None indicated in worksheet[144]
	Worksheet:	Grid Needs Assessment (GNA)
	Column:	Operating Date
SDG&E:	DIDF cycle:	2023/2024
	Workbook:	SDG&E GNA TABLES 2023 – CONFIDENTIAL.xlsx
	Version:	None indicated in worksheet
	Worksheet:	Cir-Bank Capacity
	Column:	Deficiency 2023 (MW)

Analytic Methodology

1. Summarize Load ICA at the feeder level

Results of Load ICA are summarized at the feeder level to enable their being merged with GNA results. A feeder with at least one zero-load-hosting-capacity segment is classified as a zero-load-hosting-capacity feeder; otherwise it is classified as a non-zero-load-hosting-capacity feeder.

2. Summarize GNA at the feeder level

While GNA filings included some grid needs for subtransmission substations, subtransmission lines, and distribution substations, these needs are not included in the GNA-Load ICA concordance summary because the Load ICA results pertain specifically to feeders. A feeder with a Grid Need Date of 2023 is classified as a non-zero-grid-need feeder; otherwise it is classified as a zero-grid-need feeder.

3. Assess concordance of individual feeders

Presence/absence of a grid need, combined with presence/absence of load hosting capacity, is used to classify Load ICA and GNA results for a feeder as either concordant or discordant. A numeric variable 'Concordance' is defined to enable calculation of summary concordance values for groups of feeders.

[144] The file creation date should be included in each tab of the workbook file containing GNA data. Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process, R.14-08-013, May 7, 2019. Attachment A at A1.

Table 6-10: Concordancy Matrix: Load ICA versus Grid Needs Assessment

≥ 1 segment with **Load ICA** = 0?	Feeder Level **GNA** Need Date <= 2023? No (Unconstrained)	Feeder Level **GNA** Need Date <= 2023? Yes (Constrained)
No (Unconstrained)	**Concordance = 1** Load ICA and GNA results are **concordant**	**Concordance = 0** Load ICA and GNA results are **discordant**
Yes (Constrained)	**Concordance = 0** Load ICA and GNA results are **discordant**	**Concordance = 1** Load ICA and GNA results are **concordant**

4. Calculate average concordance

After assigning Concordance values (0/1) for each feeder individually, an average Concordance is calculated as the mean of the numeric Concordance values. The result represents the proportion of feeders where GNA and Load ICA results were concordant.

<u>Results</u>

Average concordance by utility ranges from 0.25 to 0.71.

Average Concordance by Utility

PG&E	**SCE**	**SDG&E**
0.71	0.25	0.42

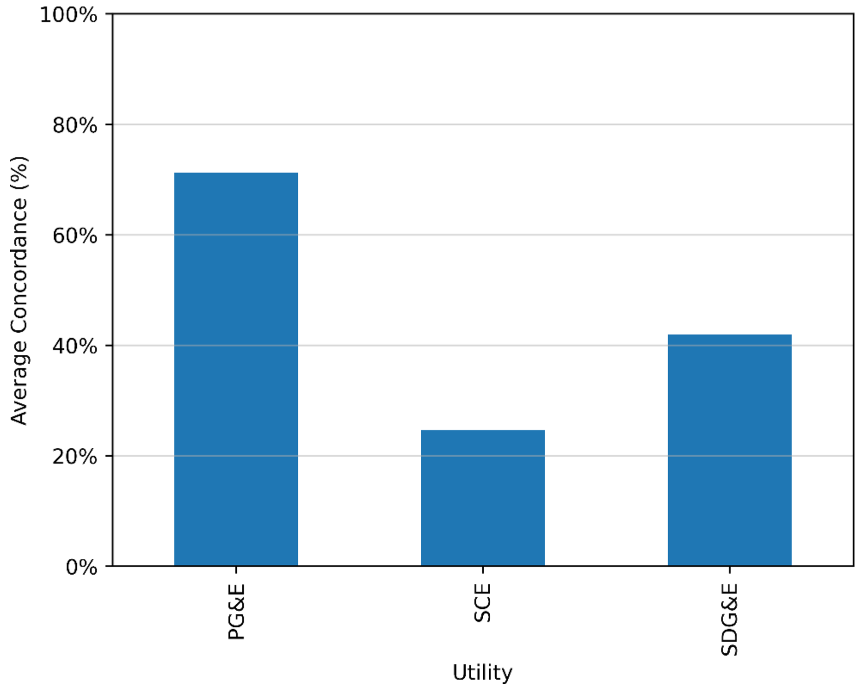


Figure 6-16: Average GNA versus Load ICA Concordance by Utility (ICA data from mid-2023)

Concordance for the possible combinations of GNA and Load ICA values is shown in the tables below. When GNA > 0, a grid need exists and the grid is classified as *constrained*. From the Load ICA standpoint, the grid is classified as Constrained when at least one segment on the feeder has a Load ICA result equal to 0. When both the GNA and the Load ICA suggest that the grid is *constrained*, these two measures of grid capacity status are described as concordant. Similarly, when the GNA and Load ICA both suggest that the grid is *unconstrained*, these two result are described as concordant. Otherwise, GNA and Load ICA results are deemed discordant.

The concordance results detail for PG&E is presented in the table below. While the average concordance for all feeders was 71%, results differ among the cells in the table.

- When Load ICA is constrained, it is very unlikely (11%) that GNA is also constrained. This suggests that filtering out poten�al project sites based on Load ICA is likely to be overly limi�ng.

Table 6-11: Concordancy Detail for PG&E Feeders

		GNA			
Load ICA		GNA = 0 (Unconstrained)	GNA > 0 (Constrained)	Total	
Load ICA > 0 (Unconstrained)		1852	109	1961	Count
		68.2%	4.0%	72.2%	% of Total
		94.4%	5.6%	100.0%	% within Row
		73.3%	56.8%		% within Column
		concordant	discordant		Concordancy
Load ICA = 0 (Constrained)		673	83	756	Count
		24.8%	3.1%	27.8%	% of Total
		89.0%	11.0%	100.0%	% within Row
		26.7%	43.2%		% within Column
		discordant	concordant		Concordancy
Total		2525	192	2717	Count
		92.9%	7.1%	100%	% within Row
		100.0%	100.0%		

Summarizing Load ICA up to the feeder level as described, 28% of PG&E feeders were classified as constrained, whereas 25% of PG&E's section-level Load ICA results were equal to 0. The difference is due to the fact that feeders may comprise a mixture both of constrained and unconstrained Load ICA sections. The GNA results suggest that 7% of PG&E feeders are constrained.

The concordance results detail for SCE is presented in the table below. While the average concordance for all feeders was 25%, results differ among the cells in the table.

- When Load ICA is constrained, it is very unlikely (2.5%) that GNA is also constrained. This suggests that filtering out potential project sites based on Load ICA is likely to be overly limiting.

Table 6-12: Concordancy Detail for SCE Feeders

Load ICA	GNA = 0 (Unconstrained)	GNA > 0 (Constrained)	Total	
Load ICA > 0 (Unconstrained)	883	14	897	Count
	22.7%	0.4%	23.0%	% of Total
	98.4%	1.6%	100.0%	% within Row
	23.2%	15.7%		% within Column
	concordant	discordant		Concordancy
Load ICA = 0 (Constrained)	2920	75	2995	Count
	75.0%	1.9%	77.0%	% of Total
	97.5%	2.5%	100.0%	% within Row
	76.8%	84.3%		% within Column
	discordant	concordant		Concordancy
Total	3803	89	3892	Count
	97.7%	2.3%	100%	% within Row
	100.0%	100.0%		

The concordance results detail for SDG&E is presented in the table below. While the average concordance for all feeders was 42%, results differ among the cells in the table.

- When Load ICA is constrained, it is very unlikely (0.5%) that GNA is also constrained. This suggests that filtering out potential project sites based on Load ICA is likely to be overly limiting.

Table 6-13: Concordancy Detail for SDG&E Feeders

Load ICA	GNA = 0 (Unconstrained)	GNA > 0 (Constrained)	Total	
Load ICA > 0 (Unconstrained)	261	0	261	Count
	41.4%	0.0%	41.4%	% of Total
	100.0%	0.0%	100.0%	% within Row
	41.6%	0.0%		% within Column
	concordant	discordant		Concordancy
Load ICA = 0 (Constrained)	366	3	369	Count
	58.1%	0.5%	58.6%	% of Total
	99.2%	0.8%	100.0%	% within Row
	58.4%	100.0%		% within Column
	discordant	concordant		Concordancy
Total	627	3	630	Count
	99.5%	0.5%	100%	% within row
	100.0%	100.0%		

Conclusion

For all three utilities, the current Load ICA data sources and analytic methodologies produce results that are likely to underestimate the grid's actual ability to integrate additional load. The discordance between the Load ICA and the GNA diminishes current usefulness of Load ICA. The Load ICA refinements expected to be completed in the 2024-2025 timeframe are expected to improve upon this situation, and make progress toward the data portals key goal of Energization Experience Accuracy. As Load ICA data sources and analytic methodologies evolve, continued monitoring of the concordance of Load ICA and GNA is one way to assess progress toward achievement of that goal.

6.4. Appendix D Documents Used in Development of the Staff Proposal

6.4.1. Interconnection correlation analysis

The PG&E ICA versus Interconnection Timelines comparison included both public and confidential data sources. The public data sources included ICA results obtained from PG&E's online ICA map, and anonymized interconnection application data obtained from PG&E's quarterly Interconnection Timelines reports. Information identified by PG&E as being **confidential** included two additional variables for interconnection applications: Feeder Name and Segment ID. Using the Feeder Name and Segment ID for each interconnection application, ICA results were associated with interconnection applications. PG&E provided additional information it identified as confidential (e.g., ‘Account Number’, ‘SA ID’) that was not used in the comparison analysis. In response to a subsequent data request PG&E provided information about the need for mitigations for select projects from the Interconnection Timelines reports; all of this information was identified by PG&E as being **confidential**.

The SDG&E ICA versus Interconnection Timelines comparison included ICA results obtained from SDG&E's online ICA map, and anonymized interconnection application data obtained from SDG&E's quarterly Interconnection Timelines reports. These data, obtained from public sources, were augmented with two additional variables for interconnection applications: Feeder Name and Segment ID. Values of these two additional variables were provided by SDG&E in response to a CPUC data request. SDG&E's response provided no indication that the data for the two additional variables was considered confidential.

The staff proposal contains results of ICA versus Interconnection Timelines comparison analyses summarized to provide high-level indications of alignment between the two sources of information about interconnection of generation capacity. No project-specific comparison results were included in the staff proposal. The level of aggregation at which results were presented masks all information specific to any individual project.

Table 6-14 shares information about the data used in analyses within this staff proposal, including the three data requests involved in the ICA versus Interconnection Timelines comparison, and details whether the data used was public or confidential.

Table 6-14. Confidentiality status of data requests and documents used in the interconnection correlation analysis.

IOU	Date Received	Document Source	Data Request Identifier	Data Requested	Confidentiality Status
PG&E	Q3 2022	Quarterly Interconnections Timeline Report	N/A	N/A	Public
SDG&E	Q3 2022	Quarterly Interconnections Timeline Report	N/A	N/A	Public
SDG&E	11/23/22	CPUC Data Request	Quarterly Interconnection Matching Data Request	ICA Feeder ID, ICA Line Segment Number	Public
PG&E	11/28/22	CPUC Data Request	ED_008-Q001	ICA Feeder ID, ICA Line Section	Confidential

PG&E	Q2 2023	Quarterly Interconnections Timeline Report	N/A	N/A	Public
SDG&E	Q2 2023	Quarterly Interconnections Timeline Report	N/A	N/A	Public
PG&E	09/25/2023	CPUC Data Request	ED_019-Q002	Mitigation and upgrade information	Confidential

6.4.2. ICA-GNA concordance analysis

All three of the GNA Excel files used for the ICA-GNA concordance analysis come from the annual DIDF filings and are confidential (Table 6-15).

Table 6-15. Table detailing information on the confidentiality status of documents used in the ICA-GNA concordance analysis.

IOU	DIDF Cycle	Document Source	Confidentiality Status
SDG&E	2023/2024	Annual DIDF Filings	Confidential
SCE	2023/2024	Annual DIDF Filings	Confidential
PG&E	2023/2024	Annual DIDF Filings	Confidential

6.4.3. Additional Documents/Resources

The following documents and resources were used to prepare and inform this staff proposal.

- Southern California Edison. “Distributed Resource Plan External Portal (DRPEP) Interactive User Guide.” October, 2023. https://drpep.sce.com/drpep/drpep-interactive-user-guide/index.html#
- Pacific Gas and Electric Company. “Integration Capacity Analysis (ICA) Map User Guide.” Version 1.11 (June 27, 2022). https://www.pge.com/b2b/distribution-resource-planning/downloads/integration-capacity/PGE_ICA_Map_User_Guide.pdf
- SCE High DER SCE Training for ED Staff ICA Methodology and External Portal, October 30, 2023
- Decision D.20.09.035 Adopting recommendations from working groups two, three, and subgroup for Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21, R.17-07-007, September 24, 2020. https://www.cpuc.ca.gov/rule21/

- Order Ins�tu�ng Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future, R.21-06-017, June 24, 2021.
- Order Ins�tu�ng Rulemaking to Con�nue the Development of Rates and Infrastructure for Vehicle Electrifica�on. R18-12-006, December 13, 2018.
- Order Ins�tu�ng Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning and Evalua�on of Integrated Distributed Energy Resources, R.14-10-03, October 2, 2014.
- Assigned Commissioner's Scoping Memo and Ruling, R.21-06-017, November 15, 2021
- California Distribu�on Resources Plan (R. 14-08-013) Integra�on Capacity Analysis Working Group
- Decision D.17-09-026 Decision on Track 1 Demonstra�on Projects A (Integra�on Capacity Analysis) and B (Loca�onal Net Benefits Analysis), R.14-08-013, December 6, 2017.
- Decision D.2018-02-004 on Track 3 Policy Issues, Sub-Track 1 (Growth Scenarios) and Sub-Track 3 (Distribu�on Investment and Deferral Process, R.14-08-013, February 8, 2018. OP#21.
- Administra�ve Law Judge's Ruling Modifying the Distribu�on Investment Deferral Framework Process, R.14-08-013, May 7, 2019. Atachment A at A1.
- Administra�ve Law Judge's Ruling on Recommended Reforms for the Distribu�on Investment Deferral Framework Process, R.14-08-013, June 21, 2021.
- Administra�ve law judge's ruling ordering refinements to load integra�on capacity analysis, Rulemaking 14-08-013, September 9, 2021.
- California Public U�li�es Commission, Energy Division. "Data Portals Workshop for the High DER Grid Planning Proceeding". (July 26 2022). htps://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/distribu�on-planning/july26dataportalsslides.pdf
- California Public U�li�es Commission. "Load Integra�on Capacity Analysis Refinements Workshop." (March 8, 2023). htps://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/distributed-energy-resources-ac�on-plan/load-ica-refinements-workshop-slides.pdf
- California Public U�li�es Commission, Joint IOU and Energy Division. "Load ICA Refinements." (March 8, 2023). https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/distributed-energy-resources-ac�on-plan/joint-iou-presenta�on--load-ica- refinements-workshop-3823.pdf
- PG&E shared their plans in the data request response 'DER-ModernizeElectricGridOIR_DR_ED_015-Q001' on June 16, 2023
- Decision 14-05-016 adop�ng rules to provide access to energy usage and usage-related data while protec�ng privacy of personal data, R.08-12-009, May 5, 2014.
- California Public U�li�es Commission, Energy Division. "EV Infrastructure Rules Data Collec�on Template." https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-

division/documents/transporta�on-electrifica�on/copy-of-ev-infrastructure-rules-data-collec�on-template.xlsx

- PG&E Improved ICA Data Valida�on Plan, Advice Leter 6212-E, May 28, 2021
- PG&E November 4, 2022, response to CPUC Energy Division October 21, 2022, data request. Ques�ons 1 and 2.
- Decision D.17-09-026 on Track 1 Demonstra�on Projects A (Integra�on Capacity Analysis) and B(Loca�onal Net Benefits Analysis), R.14-08-013, September 28, 2017.
- Decision D.16-06-011 Amended update to compliance filing of Southern California Edison Company, San Diego Gas & Electric Company and Pacific Gas and Electric Company Pursuant to Ordering Paragraph 2 of Decision 16-06-011 for Order Ins�tu�ng Rulemaking to Con�nue the Development of Rates and Infrastructure for Vehicle Electrifica�on, R.18-12-006, December 13, 2021.
- Decision D.97-10-031 Opinion Regarding the Customer Informa�on Database Workshop Report for Order Ins�tu�ng Rulemaking on the Commission’s Proposed Policies Governing Restructuring California’s Electric Services Industry and Reforming Regula�on & Inves�ga�on 94-04-032 Order Ins�tu�ng Inves�ga�on on the Commission’s Proposed Policies Governing Restructuring California’s Electric Services Industry and Reforming Regula�on, October 9, 1997.
- California Distribu�on Resources Plan (R. 14-08-013) “Integra�on Capacity Analysis Working Group Final ICA WG Long Term Refinements Report.” htps://drpwg.org/sample-page/drp/
- Senate Bill No. 350, Clean Energy and Pollu�on Reduc�on Act. October 7, 2015.