



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

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11/06/25

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R2106017

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

R.21-06-017

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E)
2025 INDEPENDENT PROFESSIONAL ENGINEER DISTRIBUTION
PLANNING ADVISORY GROUP REPORT

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Dated: **November 6, 2025**

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Pursuant to the March 6, 2025 Administrative Law Judges’ Ruling Setting Schedule for the 2025-2026 Distribution Investment Deferral Framework Cycle, Southern California Edison Company (“SCE”) respectfully submits its 2025 Independent Professional Engineer (“IPE”) Distribution Planning Advisory Group (“DPAG”) Report.

Respectfully submitted,

WILLIAM YU

/s/ William Yu

By: William Yu

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November 6, 2025

Attachment

2025 IPE DPAG Report



Independent Professional Engineer SCE 2025 DPAG Report

PUBLIC VERSION

Submitted to California Public Utilities Commission Energy Division and SCE

Date: November 6, 2025

Statement of Confidentiality

The CPUC made provision for the Investor-Owned Utilities to request confidentiality treatment for certain data submitted in their GNA/DUPR reports and other material provided to the IPE that is contained in this report. SCE has not designated any data in this report to be confidential. Thus, this PUBLIC VERSION of the report has no redacted confidential data marked in black.

In summary, this PUBLIC VERSION of the report can be distributed to any interested party since it does not contain any confidential information.

Contents

1.	Introduction and Background.....	1
1.1.	IPE Plan.....	4
1.2.	Definitions of Verification and Validation	6
1.3.	Services Considered within the GNA/DUPR Framework	6
1.4.	Approach to Information Collection	7
1.5.	Report Contents.....	7
2.	Review of GNA Report.....	9
2.1.	Scope of SCE's GNA/DUPR Reports	9
2.2.	Summary of SCE's 2025 GNA Report	10
2.2.1.	Project Data Used in Load Growth Forecasting.....	13
2.2.2.	Known Load Tracking Data.....	28
2.2.3.	Analysis of Known Load Data	32
2.2.4.	Utility Owned DER Projects	34
2.2.5.	Line Segment Needs.....	35
2.3.	GNA - Observations, Conclusions and Recommendations.....	35
3.	Review of DUPR Report.....	37
3.1.	DUPR Report Planned Investments - Observations, Conclusions and Recommendations	40
4.	Other Items of Interest.....	41
4.1.	Miscellaneous – Observations, Conclusions and Recommendations	41
5.	Verification Approach and Results	42
5.1.	PROCESSES TO DEVELOP SYSTEM LEVEL FORECASTS AND DISSAGREGATE TO CIRCUIT LEVEL	42
5.1.1.	Collect 2024 Actual Circuit Loading, Normalize and Adjust for Extreme Weather – Steps 1 and 8.....	42
5.1.2.	Determine Load and DER Annual Growth on System Level - Step 2.....	46
5.1.3.	Disaggregate Load and DER Annual Growth to the Circuit Level – Step 3	48

5.1.4.	Add Incremental Load Growth Projects to Circuit Level Forecasts (those loads believed to not be in CEC forecast) – Step 4.....	49
5.1.5.	Convert Peak Growth to 8760 Profile, Determine Net Load and Peak Load – Steps 5, 6, and 7	50
5.2.	PROCESSES TO DETERMINE CIRCUIT NEEDS AND DEVELOP GNA.....	51
5.2.1.	Process to Determine Circuit Needs - Step 9-11.....	51
5.2.2.	Compile GNA Tables Showing Need and Timing – Step 12	51
5.3.	PROCESSES TO DEVELOP PLANNED INVESTMENTS AND COSTS.....	51
5.3.1.	Develop Recommended Solution – Step 13	51
5.3.2.	Estimate Capital Cost for Candidate Deferral Projects – Step 14	56
5.4.	PROCESSES TO DEVELOP CANDIDATE DEFERRAL LIST AND PRIORITIZE	56
5.4.1.	Development of Candidate Deferral Projects – Steps 15-17.....	56
5.4.2.	Calculate LNBA Values – Step 18.....	57
5.4.3.	Compare Forecast and Actuals at Circuit Level for 2023 – Step 19	57
5.5.	OTHER IPE WORK	59
5.5.1.	Review Implementing of Planning Standard and/or Planning Process – Step 22	59
5.5.2.	Review List of Internally Approved Capital Projects – Step 23	59
5.5.3.	Respond to and Incorporate DPAG Comments – Step 24	59
5.5.4.	Track Solicitation Results to Inform Next Cycle – Step 25.....	59
5.5.5.	Treating confidential material in the IPE Report – Step 26	59
5.5.6.	Project Prioritization - Step 27	59
5.5.7.	Project Execution Tracking Data and Metrics – Step 28.....	61
Appendix A	IPE Scope	A-1
Appendix B	Copy of the IPE Plan	B-1
Appendix C	Documents and DPAG Q&A	C-1

1. Introduction and Background

Summary of CPUC April 13, 2020 Rulemaking 14-08-013 and Other Rulemakings

In August 2014, the CPUC issued Rulemaking (R.) 14-08-013, which established guidelines, rules, and procedures to direct California's IOUs to develop Distribution Resources Plans (DRPs).

In February 2018, the Commission issued Decision (D.) 18-02-004 which adopted the Distribution Investment Deferral Framework (DIDF) and directed the IOUs to file a Grid Needs Assessment (GNA) by June 1 of each year and a Distribution Deferral Opportunity Report (DDOR) by September 1 of each year. The GNA, as adopted by this decision, limits reported grid needs to four types of forecasted circuit level system deficiencies associated with the four distribution services that DERs can provide, as adopted in D.16-12-036: capacity, voltage support, reliability (back-tie) and resiliency (microgrid).

In May 2019, the assigned Administrative Law Judge (ALJ) issued a ruling that directed IOUs to file both the GNA report and DDOR on August 15 annually.

In April 2020, the assigned ALJ issued a ruling modifying the DIDF process and filings with respect to the Independent Professional Engineer (IPE) scope of work. This ruling also updated the 2020-2021 DIDF cycle schedule and defines the DIDF cycle to start on January 1 of each year and concludes July 31 the following year. Attachments A and B of the Ruling include a listing of the IPE-specific reforms discussed in the Ruling and the updated IPE scope of work. These Attachments to the Ruling are attached as Appendix A of this report. This ruling also included a new IPE Post-DPAG Report deliverable within the IPE scope of work.

In May 2020, the assigned ALJ issued a ruling modifying the DIDF process. This Ruling established 56 new reform requirements including process changes to approval for the Integrated Energy Policy Report (IEPR) dataset used for forecasting, requests for certain datasets to be hosted on the DRP Data Portals, value stacking that may result in deferral projects that exceed the cost cap, changes to how Locational Net Benefit Analysis (LNBA) data is presented, and recommendations for potential 2021-2022 DIDF cycle reforms.

In February 2021, the Commission issued IDER D. 21-02-006 which introduced the Partnership Pilot and the SOC Pilot and streamlined the DIDF RFO.

In June 2021, the assigned ALJ issued a ruling on recommended reforms to the DIDF process and revisions to some previous reforms to align with requirements adopted by D. 21-02-006.

In November 2021, the Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future (R.21-06-017) was filed to replace the 2014 Distribution Resource Plan and now stands as the OIR home for GNA and DUPR compliance.

In 2022, the Commission issued the 2022 DIDF Ruling, establishing seven reforms to three solicitation frameworks.

In May 2023, the Commission's 2023 DIDF Ruling focused primarily on updates to known load tracking and reporting, as well as terminating the SOC Pilot.

Finally, in June 2024, the assigned ALJ granted the motion filed by SDG&E and SCE, as well as a separate motion filed by PG&E, requesting to suspend portions of the DIDF process temporarily and removing solicitation-related reporting requirements within the 2024 GNA/DUPR reporting period, as well as ended the Partnership Pilot. The June 2024 Ruling also provided the regulatory timelines for the 2024/2025 DIDF cycle shown in the table below.

Table 1-1: DPAG Schedule for 2025-2026 DIDF Cycle (Partial table from the March 2025 Reform Ruling)

Activity	Date
Pre-DPAG 2025	
Pre-DPAG meetings and workshops, including Draft IPE Plans review	May-June 2025
DPAG 2025	
IOU GNA/DDOR filings Final IPE Plans Circulated	August 15, 2025
IPE Preliminary Analysis of GNA/DDOR data adequacy circulated	September 5, 2025
DPAG meetings with each IOU	Mid to Late September 2025
Participants provide questions and comments to IOUs and IPE	September 26, 2025
IOU responses to questions	October 6, 2025
Follow-up IOU meetings via webinar (Optional)	Week of October 13, 2025
IPE DPAG Reports	November 6, 2025
Post-DPAG 2025 and 2026	
IPE Post-DPAG Report (covering all three Utilities)	March 15, 2026

Independent Professional Engineer

The California Public Utilities Commission (Commission) rulings direct Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities or IOUs) to enter into a contract with an Independent Professional Engineer (IPE). The role of the IPE is as previously described.

Through a contract with Resource Innovations, SCE engaged Mr. Sundar Venkataraman¹, PE, to serve as the advisory engineer (referred to as the Independent Professional Engineer (IPE))

¹ Consistent with the CPUC decision, the contract with Resource Innovations (RI), the firm through which Mr. Venkataraman is contracted, provides for other individuals within RI to assist Mr.

for the scope described in the April 23, 2020 CPUC Ruling or as modified by subsequent rulings.

This report, which meets the requirements included in the CPUC ruling was provided to SCE in sufficient time to be included in their Advice Letter filing.

1.1. IPE Plan

As required by the April 23, 2020 Ruling, the IPE developed an IPE Plan that served to guide the IPE's steps to implement its 2023 DIDF work scope. The plan was developed using a three-step process:

1. In Step 1 the IPE developed a draft IPE Plan working with the Energy Division and SCE and distributed it on May 23, 2025.
2. The Plan was distributed to the service list and also discussed at the CPUC Distribution Forecasting Working Group meeting - both in an attempt to obtain stakeholder feedback on the plan.
3. Based upon stakeholder feedback received and under the direction of the Energy Division, the IPE revised the plan and made its IPE Final Plan available on August 15, 2025.

A copy of the Final IPE Plan is included as Appendix B.

In every DIDF cycle, the IPE reviews the plan to determine if any of the steps could be streamlined or eliminated in that cycle without compromising the intent of the verification and validation process. Such streamlining allows the IOUs and the IPE to focus additional time on more recent additions to the IPE's scope. Based on this review, the IPE has recommended and the ED concurred that the following steps can be skipped in this cycle since they agreed that their review was not expected to yield additional insights:

- Steps 5-7 - Convert Peak Growth to 8760 Profile, Determine Net Load and Peak Load
- Step 9-11 - Initial Comparison to Equipment Ratings, Evaluate No Cost Solutions and Comparison to Equipment Ratings after No Cost Solutions
- Step 12 - Compile GNA tables showing need amount and need timing, etc. (GNA tables were provided)
- Step 14 - Development of capital costs for planned investments

Venkataraman to perform the work in the IPE contract provided that these other individuals are also bound by the same confidentiality and conflict of interest requirements that Mr. Venkataraman is required to meet.

In addition, this IPE plan skips the verification and validation of the following steps due to the CPUC's elimination of DIDF procurement related processes in this cycle.

- Step 15 - Development of Candidate Deferral Projects
- Step 16 - Development of operational requirements for CDOs
- Step 17 - Prioritization of Candidate Deferral Projects into Tiers
- Step 18 - Calculation of LNBAs for planned projects

In addition, based on input from the ED, the following steps were skipped in this cycle;

- Step 21 - Review plan for changes to the planning process for the next cycle
- Step 22 - Review implementing of planning standard and/or planning process
- Step 23 - Review list of internally approved capital projects
- Step 25 - Track solicitation results to inform next cycle

Two new steps were also added:

- Step 27 - Review Methodology used for Prioritization of Planned Projects (if applicable); examine process used by utilities to develop planned investments and planned solution
- Step 28 - Review Project Execution Tracking Data and Metrics; examine the data and metrics submitted by the IOUs related to the status and timeline of distribution project execution. This will be the first cycle where IOUs will be submitting this data in their GNA/DUPR

In addition;

- Step 13, which was skipped in the previous cycle has been included in this cycle. This review will verify and validate the process used to confirm that planned projects identified in prior cycles are still needed based on the results of the analysis in the current cycle using up dated assumptions. This process is an important guardrail for pending loads and scenario planning

The business processes in the Plan are organized generally in the order that they are performed. Starting with capturing the peak load values for each circuit for 2024, using the California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) forecasts to develop utility specific system level values, which are then disaggregated to the circuit level adjusted for known loads and then used to determine if there is an overload or other issue during the planning period. For circuits that have a need, a no or low-cost solution or a capital project, if needed, is identified to address one or more needs.

1.2. Definitions of Verification and Validation

As part of the development of the IPE Plan, detailed definitions were developed to clarify the meaning of Verification and Validation as applied to the IPE scope of work. These definitions which are used and applied in all IPE deliverables are listed below:

Verification – An independent check to determine if the results were developed using assumptions and business processes that were defined and described by the utility. In other words, “Did the IOU follow their own processes correctly?”

Validation – An independent assessment of the appropriateness of the approach taken by the utility to perform task from an engineering, economics and business perspective. In other words, “Are the processes implemented by the IOU the best way to identify all necessary planned solutions and investments. And to what extent were the IOU methodologies appropriate and effective?”

1.3. Services Considered within the GNA/DUPR Framework

The CPUC, in a previous decision², approved the four services proposed by the Competitive Solicitation Framework Working Group (CSFWG) and directed the utilities to consider these services in the GNA/DUPR process. The four services described in the decision are listed below in an excerpt from the decision:

“The following definitions for the key distribution services that distributed energy resources can provide are adopted for the Competitive Solicitation Framework:

Distribution Capacity services are load-modifying or supply services that distributed energy resources provide via the dispatch of power output for generators or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure:

Voltage Support services are substation and/or feeder level dynamic voltage management services provided by an individual resource and/or aggregated resources capable of dynamically correcting excursions outside voltage limits as well as supporting conservation voltage reduction strategies in coordination with utility voltage/reactive power control systems.

Reliability (back-tie) services are load-modifying or supply service capable of improving local distribution reliability and/or resiliency. Specifically, this service

²Decision 16-12-036; definitions can be found on Page 8. Link to document below:
<http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K555/171555623.PDF>

provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations; and

Resiliency (micro-grid) services are load-modifying or supply services capable of improving local distribution reliability and/or resiliency. This service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations.”

1.4. Approach to Information Collection

The information reflected in this report was obtained through several methods including:

- Participation by the IPE in the CPUC sponsored 2022 Distribution Forecasting Working Group held on May 22, 2025
- Special conference call meetings with SCE were held to perform Verification and/or Validation Demonstration walk-throughs as described in the IPE Plan and whose results are described later in the report. These walk-throughs were held as follows:
 - June 27 - Steps 2-3a
 - July 28 - Steps 1, 8 and 4
 - September 10 - Step 19 and 20
 - September 29 - Steps 27 and 28
 - October 10 - Step 13
- Written data requests sent to SCE regarding data or their planning process that led to the needs identified in their GNA Report and the projects included in their DUPR Report. Responses from SCE were made during follow-up conference calls or in writing.
- Participation in SCE’s DPAG meeting (September 19)
- Participation in SCE’s Follow-Up DPAG meeting (October 14)
- A review of publicly available materials referred to in the discussions with SCE or materials previously filed with the CPUC.

1.5. Report Contents

The remainder of this report includes the following sections:

- **Section 2** - Review of GNA Report which briefly discusses the contents of the SCE GNA Report and the difference between SCE and other IOUs because of its Subtransmission System and any significant differences noted in SCE’s reports

between the 2025 and 2024 DIDF cycle. This section will also include discussion of known data and associated metrics. Observations, comments, and recommendations that result from the Validation review with respect to the GNA Report are included in this section.

- **Section 3** - Review of DUPR Report which briefly discusses the contents of the SCE DUPR Report, and any significant differences noted, if any, in SCE's reports between the 2025 and 2024 DIDF cycle. Observations, comments, and recommendations that result from the Validation review with respect to the DUPR Report are included in this section.
- **Section 4** - Discussion of Other Topics of Interest. Observations, comments, and recommendations that result from the Validation review with respect to these topics are included in this section.
- **Section 5** - Verification completed which reviews the approach and results of the verification performed by the IPE.
- **Appendix A** - IPE Scope - Excerpt from April 23, 2020 CPUC Rulemaking 14-08-013
- **Appendix B** - IPE Final IPE Plan - SCE
- **Appendix C** - Documents Received and DPAG Questions and Responses

2. Review of GNA Report

The GNA Report submitted by SCE on August 15, 2025 is summarized at a high level in this section.

2.1. Scope of SCE's GNA/DUPR Reports

Unlike the other two IOUs, most of SCE's subtransmission system is under CPUC jurisdiction. The SCE subtransmission system is not planned for like most utilities' subtransmission systems in that they are radial networks served by a single interconnection point from the CAISO-controlled Bulk Electric System. SCE's subtransmission system does not have multiple parallel paths for power to flow from one subtransmission system to another. SCE's subtransmission systems are contained as single networks that have parallel power flow paths from a subtransmission substation to a network of distribution substations. As a result, the majority of SCE's subtransmission systems are not subject to the CAISO Transmission Planning Process (TPP) and are planned for by SCE per SCE's planning criteria and thus are included in the GNA/DUPR process.

Below is a discussion of some of the differences between Subtransmission vs. Distribution as it relates to the GNA/DUPR process:

- SCE's distribution system and most of its subtransmission systems are under the CPUC's jurisdiction.
- Distribution facilities serve a much smaller set of customers compared to the subtransmission system, which serves multiple distribution facilities. Loads on the subtransmission can be as large as 1,000 MW.
- SCE's subtransmission system has a higher standard of reliability requirement compared to the distribution system due to the number of customers that could be impacted as a result of an outage.
- The subtransmission system is planned such that it can serve all customers during a single contingency outage condition while the distribution system is planned to serve customers when all equipment is in service. Distribution equipment outages may result in customer outages until reconfiguration of the distribution is accomplished (if feasible) or until equipment out of service is repaired and returned to service.
- Many SCE subtransmission projects in the DUPR are driven by the outage condition known as N-1 (loss of one subtransmission element).
- Such projects may be driven by capacity deficiencies and/or voltage issues that exist after a piece of equipment experiences an unplanned outage (N-1 condition).

- To avoid operating in an unreliable condition if an N-1 event occurs, certain equipment may be activated/dispatched with what is known as a pre-mitigation measure to prevent problems from occurring during an N-1 contingency condition should it occur.
- Such a pre-mitigation action might be to switch subtransmission capacitors into service to prevent low voltages if a certain N-1 is anticipated to cause an unacceptable low voltage condition.
- As a result of SCE's subtransmission system topology and the fact that it is not subject to the CAISO TPP, the projects listed in SCE's DUPR due to SCE's subtransmission system are much more varied than the projects listed in the other two IOU's DUPRs.

2.2. Summary of SCE's 2025 GNA Report

SCE's GNA Report is a written report narrative along with an Excel database of potential grid needs on its distribution and subtransmission system under CPUC jurisdiction. SCE filed its GNA and DUPR Report on August 15, 2025. In this report we only touch upon a few highlights of the report and Excel spreadsheet in the GNA Report and recommend to those who are interested in more details to review the GNA Report narrative and associated spreadsheets.

The Excel spreadsheet includes three tabs:

Tab 1- Grid Needs Assessment which includes all of the needs identified in the distribution planning process.

Tab 2 - Planning Assumptions - Distribution Subs which lists the assumptions used in the needs analysis of distribution substations.

Tab 3 - Planning Assumptions - Feeders which lists the assumptions used in the needs analysis of distribution feeders.

The 2025 GNA, which covers needs for all distribution circuits and substations and subtransmission lines and substations under the jurisdiction of the CPUC, included 701 separate entries. A comparison of the total number of needs over a five-year period is plotted later in this section.

SCE provided several tables that summarize its GNA data for 2025. For easy reference a few of these tables are duplicated here along with similar tables from SCE's 2024 GNA.

Table 2-1: GNA Needs by Asset Type from 2024 GNA and 2025 GNA

2024 GNA Total Needs by Asset Type

Asset Type	Capacity	Capacity (UCT)	Reactive Power	Reliability, Capacity	Reliability, Voltage	Voltage	Total
Distribution Feeder	96	195	64	0	0	9	364
Distribution Substation	53	0	0	3	1	0	57
Subtrans Substation	7	0	6	16	2	1	32
Subtransmission Line	4	0	0	24	1	0	29
Total	160	195	70	43	4	10	482

2025 GNA Total Needs by Asset Type

Asset Type	Capacity	Capacity (UCT)	Reactive Power	Reliability, Capacity	Reliability, Voltage	Voltage	Total
Distribution Feeder	137	348	58	2	0	12	557
Distribution Substation	75	0	0	1	0	0	76
Subtrans. Substation	7	0	5	12	2	0	26
Subtransmission Line	12	0	0	30	0 +	0	42
Total	231	348	63	45	2	12	701

Table 2-2: Summary of Grid Needs by Distribution Service Type and Region from 2024 and 2025 GNA

2024 GNA Total Needs by Type and Region

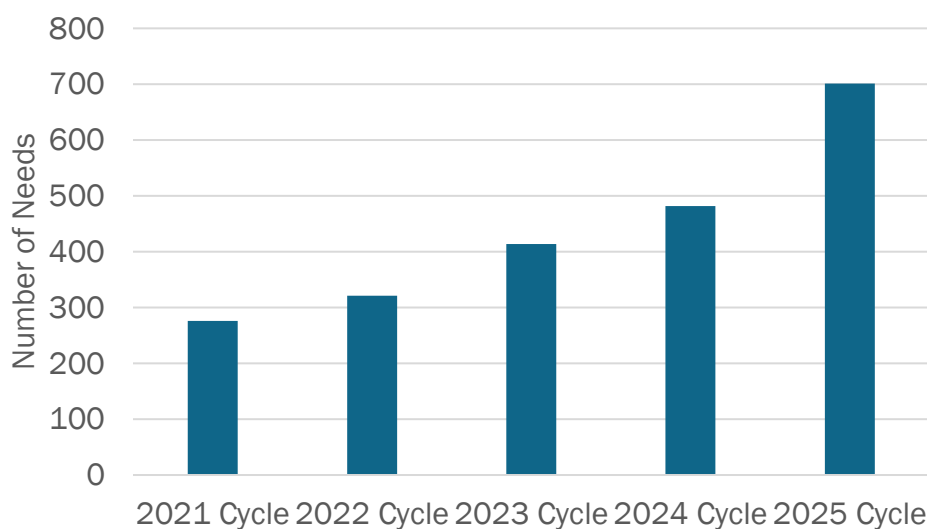
Region	Capacity	Capacity (UCT)	Reactive Power	Reliability, Capacity	Reliability, Voltage	Voltage	Total
Desert	25	39	7	12	0	1	84
Metro East	32	45	17	7	0	4	105
Metro West	45	13	7	4	0	3	72
North Coast	23	31	12	10	3	0	79
Orange	9	31	14	2	0	0	56
Rurals	15	16	4	1	0	2	38
San Jacinto	8	9	8	4	0	0	29
San Joaquin	3	11	1	3	1	0	19
Total	160	195	70	43	4	10	482

2025 GNA Total Needs by Type and Region

Region	Capacity	Capacity (UCT)	Reactive Power	Reliability, Capacity	Reliability, Voltage	Voltage	Total
Desert	34	80	6	10	0	5	135
Metro East	45	77	13	16	0	4	155
Metro West	74	16	7	3	0	0	100
North Coast	4	20	5	2	1	0	32
North Valley	21	18	5	6	1	1	52
Orange	13	70	9	3	0	0	95
Rurals	17	21	10	2	0	2	52
San Jacinto	15	24	8	3	0	0	50
San Joaquin	8	22	0	0	0	0	30
Total	231	348	63	45	2	12	701

In Figure 2-1 below the total GNA needs are plotted for the last five years. Analyzing this data indicates that the number of annual needs shows steady growth over 5 years that totals over 250% growth over that five-year period

Figure 2-1: Number of Needs Over Last Five Cycles



The GNA Report also includes a detailed description of SCE's planning process which includes detailed description and in some cases examples of 1) developing the starting point for load forecasts, 2) developing SCE system level load and DER growth using CEC IEPR data, 3) disaggregation of system level data, 4) processing of embedded and incremental load growth projects, 5) development of load and DER profiles, 6) determining if any assets will be

overloaded based upon these forecasts, 7) determining if there is a no cost solution to mitigate the overload, and 8) if not, develop a project that will resolve the overload. The verification of these and other steps are covered, if applicable in Section 5 – Verification.

Microgrid Projects

SCE indicated that they do not currently develop projects that utilize local generation to serve customers over utility distribution lines in a Microgrid configuration within its annual planning processes and therefore, there are no Resiliency service needs (sometimes referred to as Microgrid services) included in SCE's 2025 GNA.

2.2.1. Project Data Used in Load Growth Forecasting

SCE used several types of project or customer forecast data in its load forecasting process in this cycle including the following types of data:

- Incremental known load project data
- Embedded known load project data
- Vendor forecasts of new EV commercial charger load data
- Truck Stop Electrification
- Port Load Growth
- SCE Fleet Conversion to EV charger data
- IEPR data for LD EVs and MD/HD EVs
- IEPR Non-EV data
- Building Electrification
- Other IEPR DER data (EE, PV, ES)

These types of load growth were used as described in the following sections to develop a net load growth forecast that was as input to the DPP.

Incremental Known Load Growth Projects

SCE utilized load growth projects in the 2025 DIDF cycle as it has done in the recent past to develop its forecasts at the circuit level with one change from 2024. In 2025, Vendor Forecasts, Port MDHD loads and Truck Stop Electrification which are treated as additive to the IEPR, previously categorized as Incremental Known Loads in 2024, were designated as pending loads. These loads are additive to the Incremental Known Loads which are driven by

complete or nearly complete customer requests for new or additional service. All of these loads which are considered by SCE not to be included in the IEPR load growth forecast are therefore treated as additive to the IEPR forecast.

The Incremental Known Load projects are based upon input from SCE planning engineers who are familiar with the plans for new customers in their planning areas and are determined to be incremental to the CEC IEPR by SCE. As we will see in the discussion below, these Incremental Known Loads fall into five categories in the 2025 DIDF cycle – cultivation, Commercial EV supercharging stations, Load WDAT³, Temporary Power⁴ and Customer Substations.

Table 2-3 shows how the type of known loads that have been treated by SCE as incremental have changed over time. From the table we see that the same five types of loads have been used in the 2025, 2024, 2023, 2022 and 2021 DIDF cycles and that starting in 2023 and 2024 additional loads were considered incremental to the IEPR including Vendor Forecasts, Port Shore Power and Port MDHD and Truck Stop Electrification as shown in the table. Note that the legal requirement for using the IEPR as a starting point for distribution planning first occurred in 2017 but was not incorporated until 2018.

Loads that are considered as incremental are considered not included in the IEPR and therefore are added at the circuit level without any constraint.

³ Load Wholesale Distribution Access Tariff. Power purchased by a customer from generation sources on the (Independent System Operator) ISO grid and power transported from ISO grid to the customer using the Distribution Provider's electrical system.

⁴ A utility-connected source of power that is fed to a job site to serve the load of the equipment used in the construction of a structure. The temporary power is removed from service when the construction is complete, and the newly constructed building is fed from its permanent power supply.

Table 2-3: Incremental Load Growth Projects Over the Years

Incremental Projects Over the Years

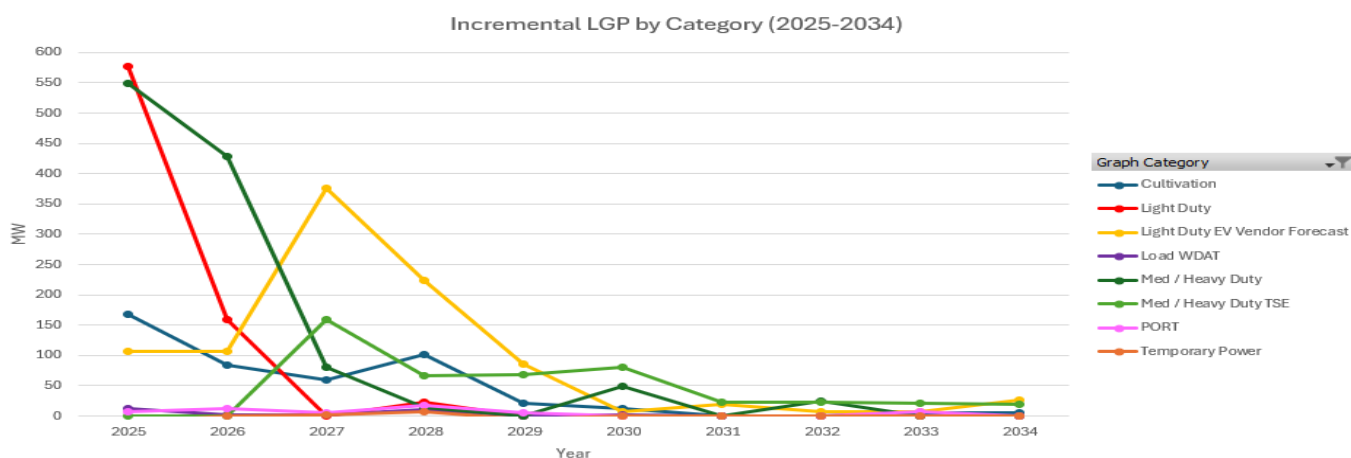
	2017	2018	2019	2020	2021	2022	2023	2024	2025
No Limits and no incorporation of IEPR*	X								
Cultivation		X	X	X	X	X	X	X	X
Commercial EV Chargers			X	X	X	X	X	X	X
Temporary Power		X		X	X	X	X	X	X
Load WDAT				X	X	X	X	X	X
Customer Subs for Transmission Substation Planning					X	X	X	X	X
EV Vendor Forecast**							X	X	X
Port Shore power, Port MDHD, TSE**								X	X
Data Centers, Facility Expansion and Spec Buildings >=2.5 MVA		X							
Agricultural Pump Load		X	X						
Mega Tract Homes		X	X						
Reservation and Government funded projects		X							

*IEPR legal requirement occurred in 2017 but was not incorporated until 2018

** Pending Load, but also incremental

In many of the past cycles, the predominant LGP load was incremental growth attributed to cultivation load with EV chargers second. This changed in the cycle before last when EV Charger LGPs exceeded cultivation LGPs. In this cycle, we can see that in [Figure 2-2](#) (top plot) the various EV charger LGPs are dominant.

Figure 2-2: Incremental LGP by Category



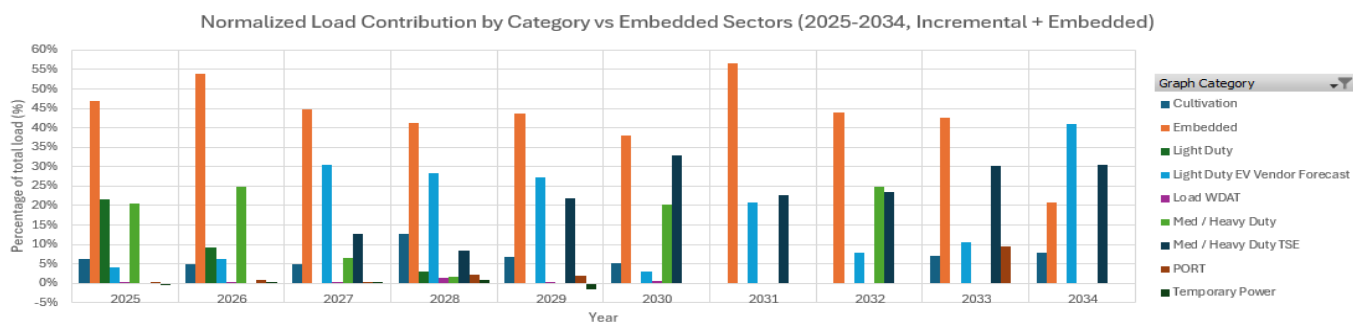
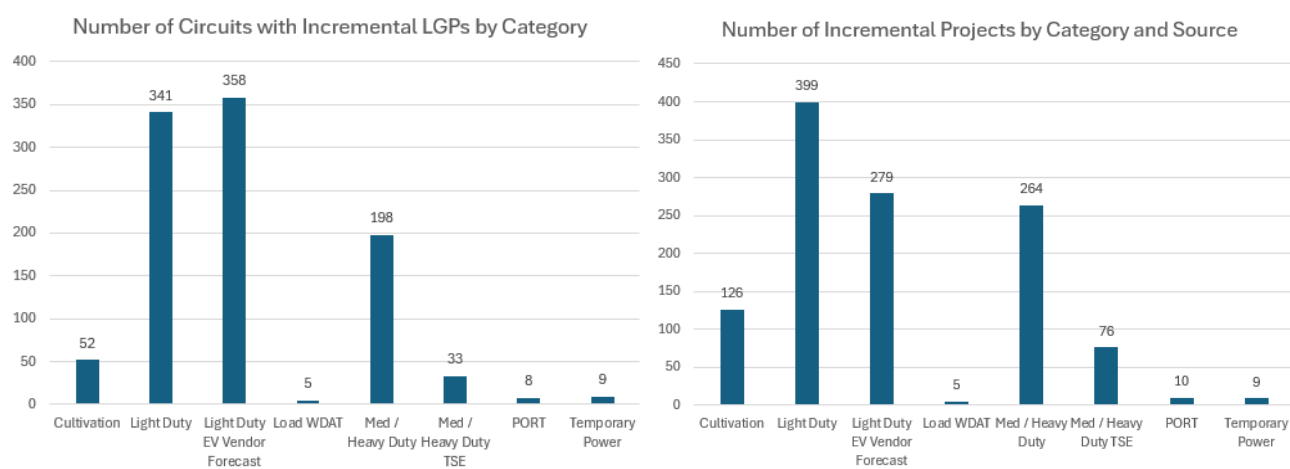


Figure 2-3: Number of Circuits and Projects with Incremental LGPs by Category



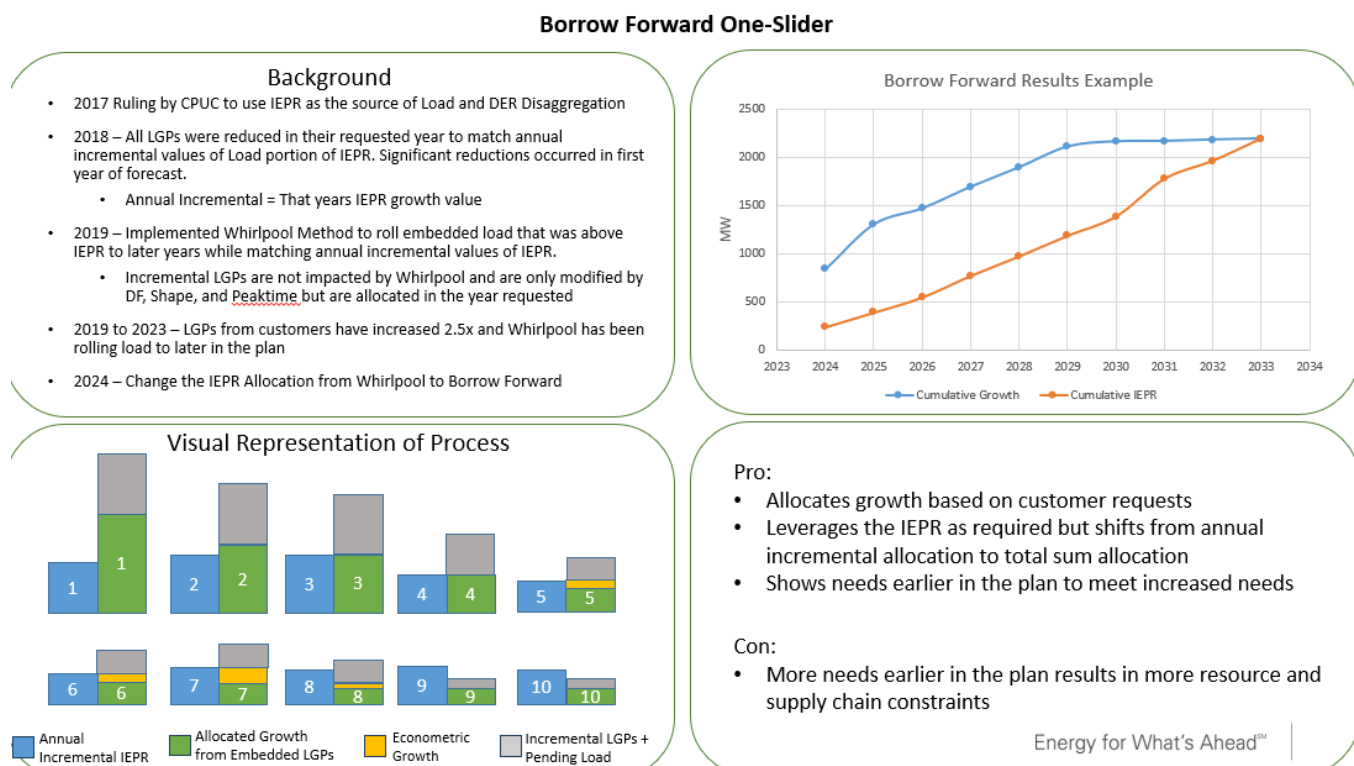
Embedded Load Growth Projects

SCE designates all Known Loads that do not fall into one of the five categories designated as Incremental Known Loads previously discussed as Embedded Known Load Growth projects. SCE assumed that these known loads were included in the CEC IEPR forecasts. By definition, TE Known Loads cannot be considered an Embedded Known load. These embedded load projects are driven by customer requests for new or increased load as are the Incremental Known Load projects. SCE used a process known as the Whirlpool Method in several past cycles to ensure that the annual sum of the embedded loads did not exceed the annual IEPR load growth amount. Starting last cycle, SCE used a new process that it referred to as the Borrow Forward Method. In this method, Embedded Known Load projects are added at the circuit level in the year that the customer requested the new or additional service and are no longer constrained by the IEPR annual or cumulative load forecast. The Borrow Forward method is used to determine how much, if any, and when econometric load growth can be added to the overall load growth forecast used in the DPP. The Borrow Forward Method provides for the addition of econometric load during the forecasting period (assumed to be

up to 15 years in the SCE Borrow Forward approach) if the cumulative IEPR non-EV load exceeds the cumulative embedded load. In this cycle as was the case in the last cycle, due to the large number and amount of embedded load projects, using the Borrow Forward Method did not result in the inclusion of any econometric load in the forecast.

The chart in [Figure 2-4](#) provided by SCE shows graphically how its Borrow Forward methodology is generally applied. This figure does not reflect this cycle's data, instead it is intended to show how a typical year's embedded load known loads would impact the forecasting process using the Borrow Forward approach. The impact of the Borrow Forward approach in this cycle is discussed later in this section.

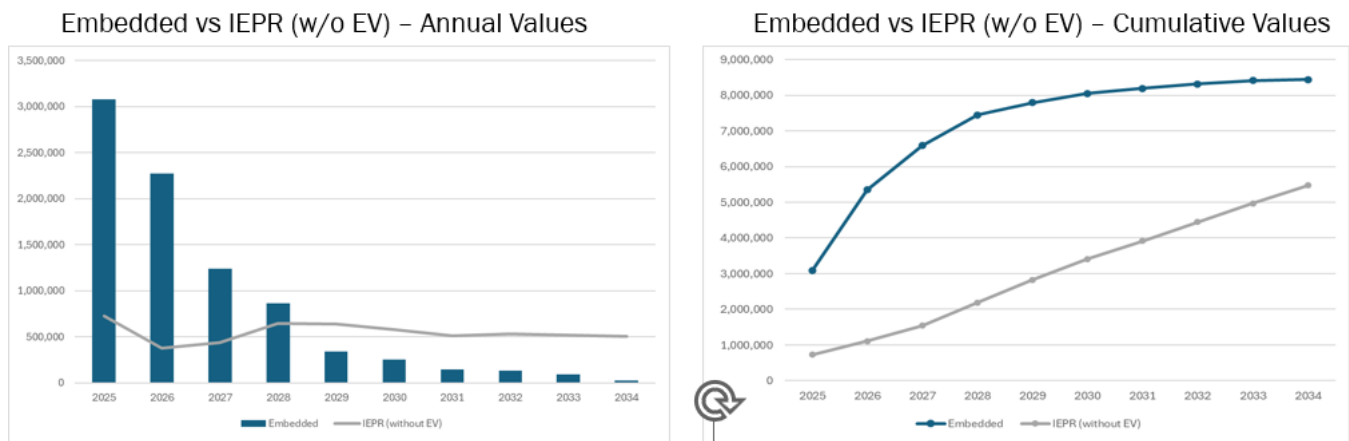
Figure 2-4: SCE Borrow Forward Method



All told there are 1783 embedded load projects (ongoing and new) included in the 2025 GNA forecasting process that total 3279 MVA over the ten-year planning period. For comparison, in the last DIFD cycle there were 1650 embedded projects included in the GNA forecasting process that totaled 2318 MVA over the ten-year planning period, which represents an increase of 41% in MVA compared to the previous cycle's MVA.

For this cycle, the annual total (in MVA) of embedded load growth projects is shown in the left plot of Figure 2-5 in blue and the annual IEPR load growth is shown by a grey line. Neither include any EV loads. We can see that the embedded load totals exceed the IEPR annual growth for the first four years. On a cumulative basis, we see on the right plot that the embedded load energy (MVA) exceeds the IEPR energy (MVA) for all of the ten-year forecasting period. As a result of applying the Borrow Forward Methodology in this cycle, there is no econometric load growth in the forecasting period since the cumulative embedded load growth exceeds the cumulative IEPR load growth (excluding EVs) in all years.

Figure 2-5: Embedded Load Growth Projects vs IEPR



Econometric Load Growth

This system level load component is used when the Borrow Forward method results in adding econometric load to individual years of the planning period. This load would be disaggregated to the circuit level using an appropriate adoption propensity methodology. As mentioned earlier, there is no econometric load growth in this cycle.

Vendor Commercial Charger Forecast - (Pending Load)

SCE also incorporated growth for planned new commercial charging stations which is based upon information received from EV Commercial Charger developers. This information, referred to as Vendor Forecasts, is based upon discussions with commercial charging vendors who have yet to formally request for new or additional service for these charging stations. Starting last cycle, SCE was able to get enough information from the vendors to forecast what circuits these new loads would be served by and therefore located these new loads at specific locations on specific distribution circuits. In the 2023 cycle, SCE applied them at the substation level during the DPP. These loads were designated as pending loads in the 2025 cycle. These loads are treated in a manner similar to incremental loads in that they are added at the circuit level and not constrained by the IEPR load forecast. There were 795 Vendor Commercial Charger Loads in this cycle with a total load of 939 MVA after application of the discount factor.

Truck Stop Electrification - (Pending Load)

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SCE incorporated charging stations along traffic corridors with high volume of truck traffic. The basis for these estimates are studies by consultants engaged by SCE. SCE indicated that the IEPR did not capture these new loads according to their consultant's study. There is a total of 306 MWs of TSE (after applying a discount factor) over the ten-year planning period. These loads were designated as pending loads in the 2025 GNA/DUPR.

Port of Long Beach - (Pending Load)

Port of Long Beach - SCE incorporated load on its circuits that supply charging stations on the Port of Long Beach property. SCE indicated that this data is based upon information received during customer engagement with the Port of Long Beach and numerous entities that are located on the Port property. SCE indicated that the IEPR did not capture these new loads. There is a total of 58 MWs of Port known loads (after applying a discount factor). These loads were designated as pending loads in the 2025 cycle and are applied at the circuit level without any constraint.

SCE Fleet Conversion (Pending Load)

SCE incorporated the planned conversion of their vehicle fleet to EV vehicles as a load growth component. These annual loads are relatively small compared to the other components discussed here. These loads are designated as pending loads in the 2025 GNA/DUPR. These loads are applied at the circuit level and are not constrained.

IEPR LD and MD/HD EV Load Growth

This system level load growth data is included in the IEPR forecast and is made up of two data sets - one for LD EVs and a second for MD/HD EVs. SCE uses a propensity adoption methodology to disaggregate this system level data to the circuit level without any constraint.

IEPR Non-EV Load Growth

This system level load growth data is included in the IEPR and is made up of a single data set. SCE uses this load forecast to determine if any econometric load should be added to the Embedded Load using the Borrow Forward methodology described earlier.

Other DER Components

Building Electrification - SCE incorporated new load to capture the additional load that is forecast to develop to support building processes that are currently on fossil fuel converting to electricity, including for example, use of heat pumps, electric water heating, etc. These load growth estimates are from the IEPR and are additive to the IEPR base load growth

estimates as intended by the CEC's IEPR. This load growth is relatively small for the first part of the forecasting period totaling only 236 MWs over the first 5 years and grows by 582 MWs over the last five years.

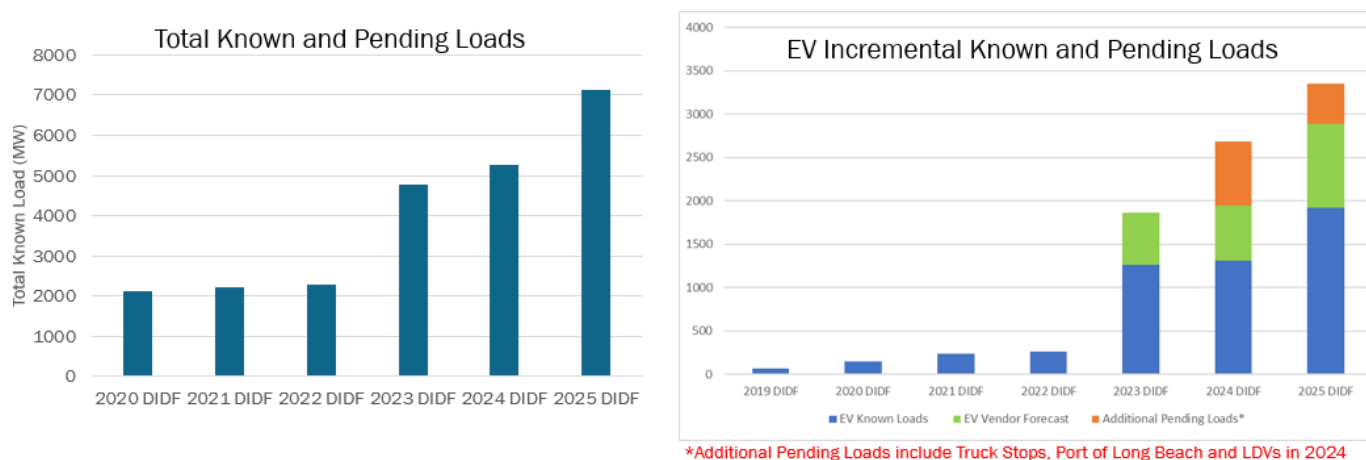
Energy Efficiency - SCE incorporates energy efficiency in its net load growth estimates which results in a decrease of load. These estimates are driven by the IEPR.

PV Generation - SCE incorporates PV production in its net load growth estimates which results in a decrease of load. These estimates are driven by the IEPR.

Known and Pending Load Growth

Figure 2-6 below shows on the left how known plus pending loads which include all types of loads including EVs has changed over time. On the right it shows how EV known and pending loads have changed over the same period. Both have experienced rapid growth. We also observe that EV growth (about 3400 MVA) is nearly half of the overall growth (7100 MVA) of known and pending load.

Figure 2-6: Known and Pending Load Growth



Incorporating Load Growth Data Components Summary

The net load that is used in the DPP is an aggregation of the various load components discussed above. The summary below presents a conceptual process⁵ (not a literal

⁵ A detailed description of the process SCE used in included in their GNA/DUPR report in Section 4.

description of the process) used to develop the net load growth forecast at the circuit level using the load growth components:

- Develop the starting point load based upon the previous year's peak circuit load normalized for weather.
- The Embedded Know Load projects are added at the circuit level in the year requested by the customer without IEPR constraint
- The Borrow Forward Method is used to determine if any system level Econometric load growth should be added. If so, the system level load growth that is added is disaggregated to the circuit level and added to the net load at the circuit level.
- Incremental Known Loads are added at the circuit level
- The IEPR system level LD EV and MD/HD EV load growth is disaggregated to the circuit level and then added to the net load at the circuit level.
- The IEPR Non-EV load growth is disaggregated to the circuit level and then added to the net load at the circuit level. (This is only used if economic forecast needs to be used to disaggregate the remaining IEPR non-EV load growth (if any))
- Vendor Forecasts. Truck Stop Electrification and Port of Long Beach load growth are pending loads that are added to the net load at the circuit level.
- SCE Fleet Electrification is added to the net load at the circuit level
- Other DERs at the system level are disaggregated to the circuit level and added to the net load at the circuit level.

Double Counting

With the many transportation electrification known load growth components that are treated as additive to the IEPR in SCE's DPP process the question naturally arises - Is there the potential for some load growth to be double counted in the DPP forecast process?

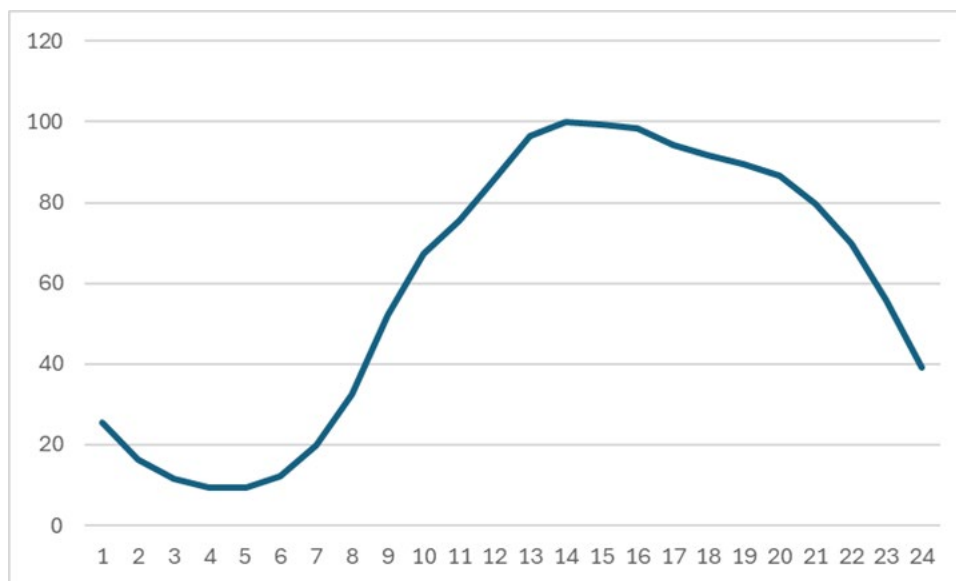
The issue of whether there is the potential for double counting between the IEPR LDV and the CEVT (energization requests for EV charging stations) load components has been raised by stakeholders. Discussed below is our understanding of the process used to develop both of these load forecast components.

Commercial Electric Vehicle Tracker (CEVT)

SCE maintains a list of public chargers that have submitted customer energization requests in its CEVT database. For each charging station, SCE develops a peak load estimate based on the customer energization request and its own experience with similar commercial charging customers. This peak load is converted into an hourly profile using a per-unit DCFC charging profile, as shown below. The profile is scaled to the peak load; the resulting energy is whatever results from that scaling process. Thus, CEVT load component is not driven by IEPR

load, vehicle count or energy values instead it is driven by what owners of commercial charging stations are requesting for service to their charging station.

Figure 2-7: Daily DCFC Charging Station Profile

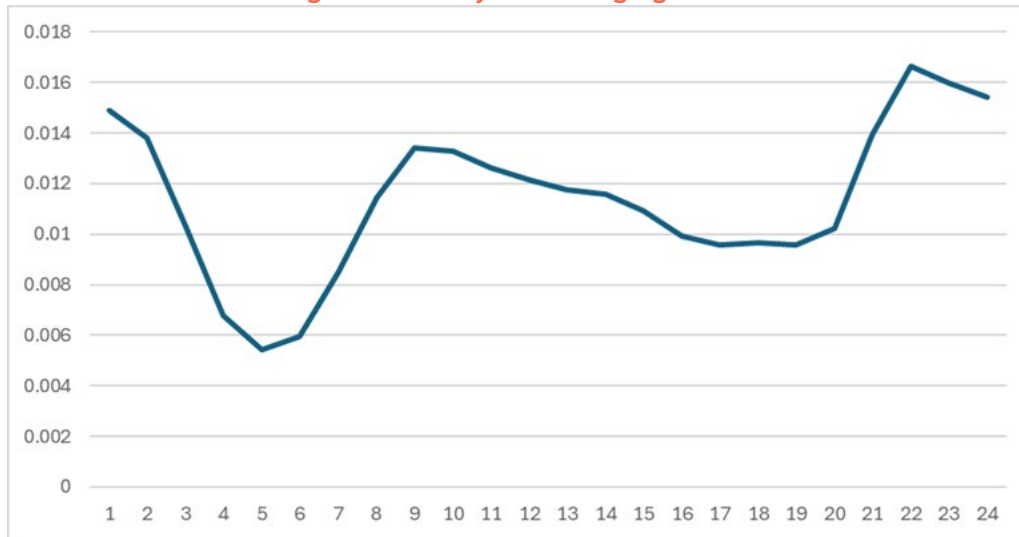


Light Duty Vehicle Charging

SCE uses the CEC IEPR LDV energy and vehicle count to forecast the IEPR LDV load component. The California Energy Commission (CEC), as part of IEPR, develops annual forecasts of light-duty vehicle stock and associated energy consumption for each forecast year. The CEC also develops average hourly profiles for LDV based on the assumptions regarding home charging and public charging. However, only the system level stock and energy values are used by SCE as inputs into their modeling the peak load impacts of light-duty vehicles.

SCE uses a disaggregation methodology to disaggregate the LDV vehicle counts and energy to the circuit level. SCE then applies a daily profile similar to the one shown below to convert the energy disaggregated to the circuit into a load profile. The profile used is representative of home charging.

Figure 2-8: Daily LDV Charging Profile



At any given time, some of the LDV IEPR energy comes from home chargers while the remaining comes from public charging stations. However, it is difficult to predict the exact location of charging for light duty vehicles i.e., whether energy will be drawn from home chargers or public chargers on a given day.

At one extreme, on a given day, all charging energy could come from home chargers, while on another day all energy could come entirely from public chargers. Distribution system planning must consider both of these scenarios which SCE's approach does. SCE's approach to developing LDV load growth forecasts is based upon the first scenario - that all energy could come from home chargers. This does not represent double-counting; rather, it recognizes that the daily energy, in full, could materialize at either location on any given day.

Questions have been raised about this approach - should the LDV forecast be based upon the extreme case assumption that all energy is being delivered by home chargers? or Is that assumption comparable to or more stringent than planning for a 1-in-10-year reliability level?

Others have suggested that energy associated with public commercial charging stations (CEVT) be removed from the IEPR LDV energy before developing the LDV forecast as an alternative to using the extreme case scenario discussed above.

SCE does not subtract the energy associated with public charging stations (CEVT) from the LDV energy forecast. While there is a possibility of over predicting the peak load with the method used by SCE, taking the approach of dividing the IEPR energy forecast between home charging and public charging (based on averages) could result in under predicting the peak load for the reasons explained earlier.

The IPE recognizes that this topic is of importance to stakeholders and distribution planning in order to minimize over or under peak forecasting for a critical load growth component. The IPE will gather additional information regarding the modeling of LDV loads and include their findings in the Post-DPAG report.

Comparison of Known Load Growth Components to IEPR

To see the overall impact of the application of all of the load components previously discussed (including incremental and embedded known loads, Vendor EV Charger Forecasts, TSE, Port of Long Beach, SCE Fleet Conversion, Building Electrification, Energy Efficiency and PV production, we examine system level total energy forecast data in Figure 2-9.

The plot on the left shows the annual energy forecast total and each of the load components previously discussed and the grey line which is the total IEPR energy. The four bar chart components include embedded and incremental known loads, pending loads and the IEPR EV growth. The grey line is the IEPR growth which includes EVs.

The right chart plots the cumulative values of the IEPR with EVs (grey line) and all load components (red line). We can see on an energy basis that the cumulative load growth of all of the components included in the DPP is substantially larger than the IEPR by roughly a factor of 2.5 at the end of the planning period and by a factor of 1.4 at the end of the ten-year period. Note the impact of other DERs is not captured in these plots.

Figure 2-9: Net Load Growth Forecast Components and IEPR Energy

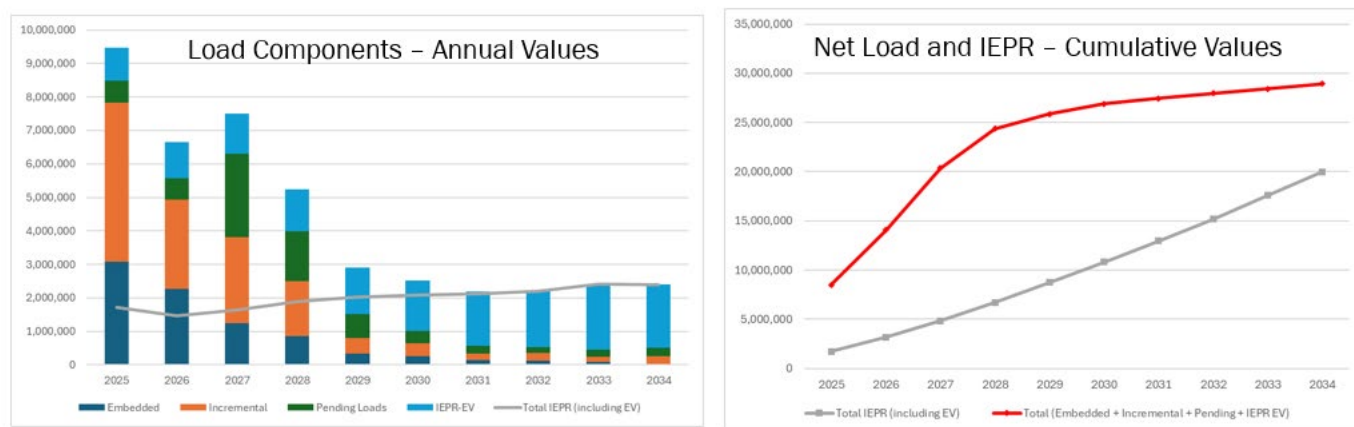
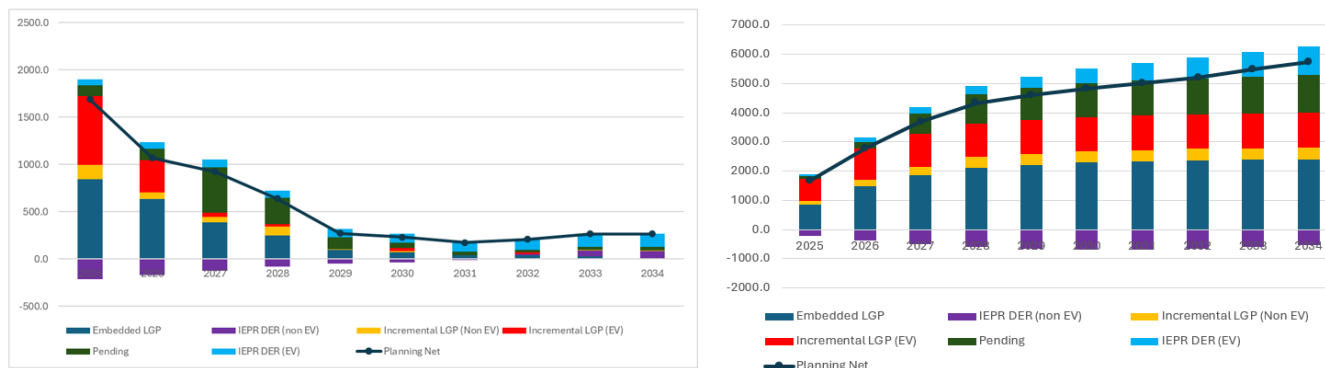


Figure 2-10 shows comparable data on a peak basis (MWs) along with data showing the impact of other DERs (EE, BE and PV DERs). The plot on the left includes bars for embedded and incremental (with and without EVs) known loads, pending loads as in

the previous plots but also includes IEPR DERs (EV and non-EV). The left plot also includes a black line that shows the net peak load that was used in the DPP.

The plot on the right shows the cumulative values of the data on the left plot. Again, the black line is the peak value that was used in the DPP.

Figure 2-10: Net Load Growth Forecast Components and IEPR Peak MW

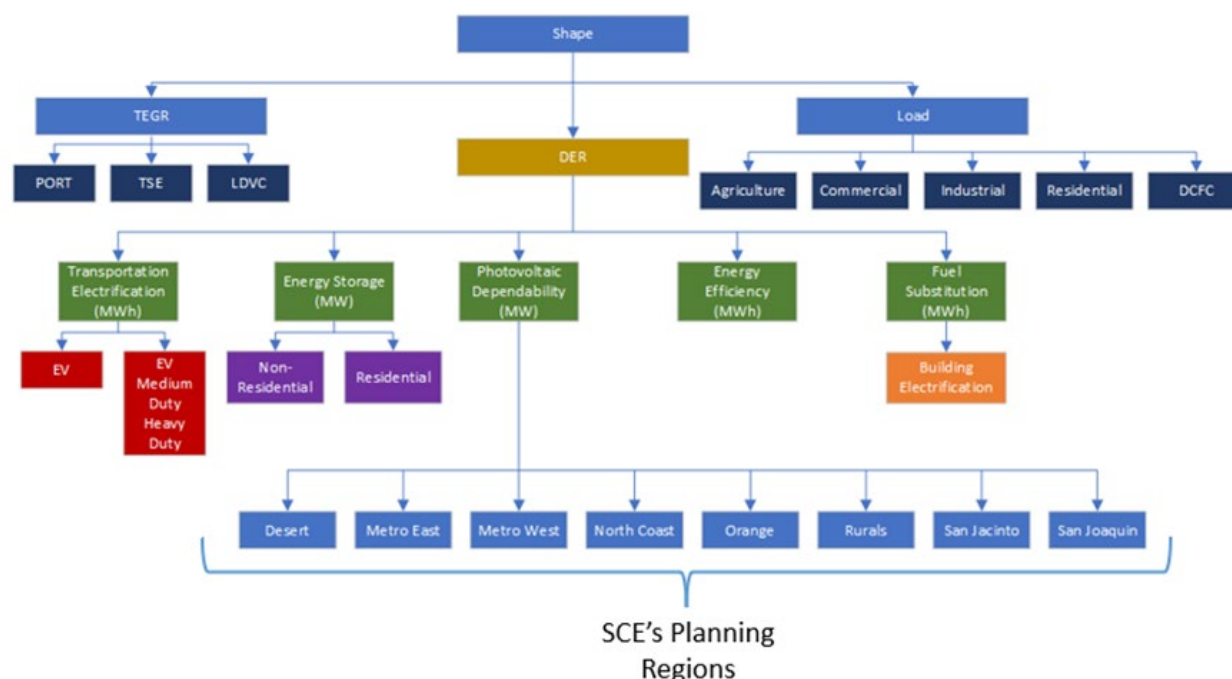


DER and EV Shapes and Profiles

In this section we discuss the load profiles or shapes that SCE used in its DPP in the current cycle to represent load and DERs.

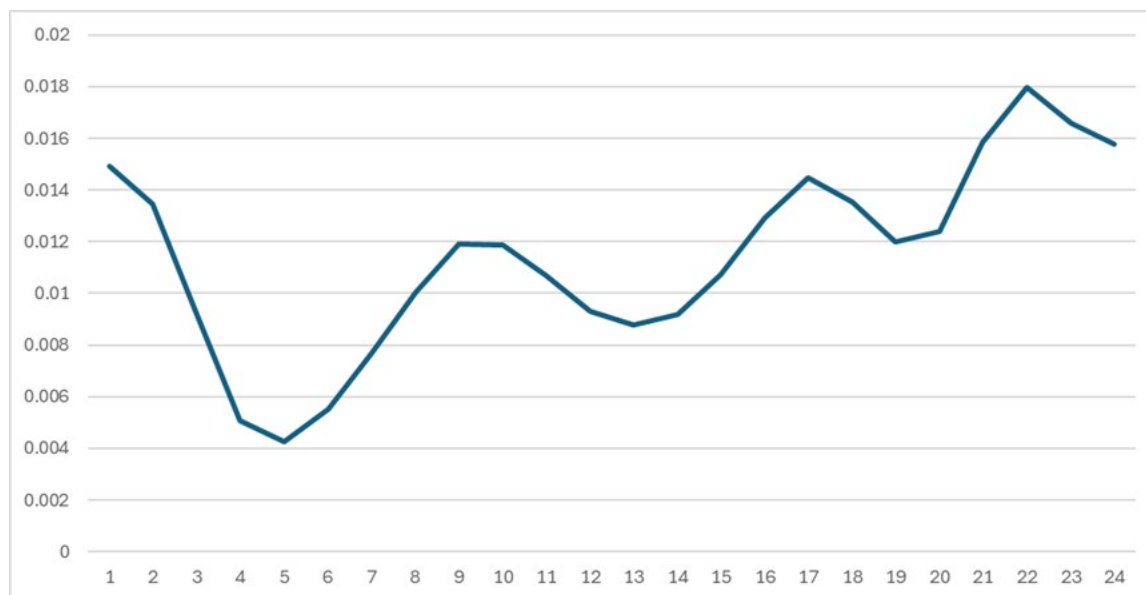
SCE indicated that their overall approach to shapes and many of the shapes used in the current cycle are the same as those used in the previous cycle. The figure below (Figure 2-11) depicts the overall approach SCE used in applying shapes in the DPP process for the previous cycle. Only one change was made to this approach for this year's cycle - the three shapes below the TEGR box are now shapes for Port Shore Power, Port MDHD and TSE. The TEGR LDVC category has been dropped and is no longer a separate load component.

Figure 2-11: Load Growth Component Shapes and Sources 2024 Cycle



SCE provided a copy of the shapes used in this cycle. The IPE performed a sanity check of the shapes used by visually reviewing the shapes and how they relate to typical SCE TOU rate periods that are expected to impact charging due to the incentives built into rates to avoid charging during peak periods. In our review we found one shape (IEPR LDV Charging) that seemed to indicate that noticeable charging would occur during the peak period. The shape in question is the shape used for LDV charging included as one of the IEPR load growth components which was disaggregated to the circuit level in this cycle as discussed above. In viewing the shape, we see a noticeable amount of charging in hour 17 which occurs during the TOU Peak Rate period (approximately 4PM to 9PM). We would have expected that such a peak would occur outside the peak period. The IPE followed up with SCE and found that SCE expects customer behavior to change over time with increased response to TOU price signals and other signals. To reflect those changes SCE used different shapes to represent this type of charging in each year of the forecasting period. In the last cycle the shape that was analyzed by the IPE was for planning year 2030 and the shape initial reviewed in this cycle was for planning year 2025 with the 2025 shape showing less customer response to TOU rates than the 2030 shape. We examined the other shapes used in this planning cycle for later years and found that, as one would expect, the shapes showed an increased response to price signals in each succeeding year.

Figure 2-12: IEPR LDV Charging Daily Shape Used in DPP



2.2.2. Known Load Tracking Data

This section in SCE's GNA shows how SCE is addressing Reform 2.6 from the 2022 DIFD Ruling. This reform directly relates to how known load projects or LGPs are tracked and whether LGPs materialize. Reform 2.6 requires the IOU's GNA/DUPR filings to include a detailed review of known load projects, including but not limited to, types of loads, number, amounts, and timing. The reform requires that a summary shall also be included similar to the evaluation provided in Section 3 of the March 17, 2022 IPE Report.

To address this requirement SCE's GNA included, for the third time, a section describing the Known Load Tracking Data that is included in its GNA Report along with the metrics that were calculated using tracking data⁶. Known load data were included in SCE's 2022, 2023 and 2024 cycle GNA reports. Beginning in the 2023 cycle SCE was required to calculate a number of pre-defined metrics using the 2022 and 2023 sets of known load data to determine how these known loads have changed over that two-year period. The ultimate objective is to gauge how certain known load data is given that known load data is critical to the forecasting process since it is a dominant factor in the load growth forecasts as discussed earlier in this report. The metrics are an attempt to answer questions, for example, how often do customers

⁶ The data values discussed in this section related to known loads are values that are before the application of a Discount Factor that SCE uses to account for the diversity of the customer's load and a circuit's loading. The average discount factor is about 0.8.

cancel requests for service or delay the start of service or reduce their requested amount of service.

The Known Load Projects report that accompanies SCE's 2025 GNA/DUPR filing includes the following information:

- the impacted circuit, unique project identifier, load type, load category, IEPR status, requested load amount, initial service request date, current expected in-service date, status, actual in-service date, and actual load amount.

In the 2023 DIDF Ruling 31, the usage of the term "Load Sector" in relation to Known Load Project tracking was replaced with "Load Type". The "Load Type" can be one of six categories: Agriculture, Commercial, Residential, Industrial, Transportation or Energy Storage. SCE does not have any projects that are classified as the Energy Storage type. Listed below is a description of the data included in the tracking data:

- The "Status" indicates whether the service request was completed, cancelled, ongoing, or new.
- The "Load Category" is a subset category of each of the six load types. For example, the Commercial type may include load categories of Education, Health Care, Business, and Other.
- The "IEPR Status" represents where the Known Load Projects are Embedded or Incremental (see Section 4.2).
- Embedded known loads are those that SCE identifies are already accounted for in the CEC IEPR forecasts and Incremental known loads are those in addition to the CEC IEPR forecast (see Section 4.2)
- The "Requested Load Amount (MVA)" represents the total load amount requested by the customers over 10 years of the planning process. This does not account for loading adjustments that take place in SCE's load disaggregation process.
- The "Actual Load Amount" is not available for the 2025 GNA/DUPR filing. SCE will further explore how to include this information in future filings.

To align with the Project Execution template, the following fields were updated by SCE:

- The "Initial Service Request Date" will be renamed to "Energization Request Date" and represent the date when the Known Load Project was submitted by the customer. SCE is currently working on establishing a process to capture the actual energization dates for LGP customers.
- The "Current Expected In-Service Date" will become the "Planned Energization Date" and represent the date the Known Load Project is expected to be energized.

- The “Actual Service Date” will become the “Actual Energization Date” and represent the date the Known Load Project was energized. SCE is currently working on establishing a process to capture the actual energization dates for LGP customers, but for this report’s purposes we will populate this field with the Planned Energization Date

Note: SCE does not track historical in-service dates. In cases where insufficient data exists to determine the specific year an existing Known Load Project was energized, SCE will use January 1 of the earliest year that load occurs in the latest planning cycle. For example, some customers have been in service for many years but request more load over time in the same location as business expands. SCE monitors the increase of load over time by keeping track of load schedules moving forward but not when service was initially provided.

- The “DUPR ID” will represent which projects on the DUPR are associated with each Known or Pending Load.

SCE included “pending loads” in the tracking data that was reported in this cycle but did not include pending load data in the Known Load Tracking Data metrics to be consistent with a CPUC decision.

SCE developed metrics using the 2024 and 2025 Known Load Tracking Data that were specified in the IPE’s March 17, 2022, SCE Report. These metrics are similar to the metrics included in SCE’s 2024 GNA/DUPR Report. SCE noted in its GNA/DUPR narrative that Vendor Forecasts were classified as known loads in 2024 and thus were included in the metrics in 2024 GNA/DUPR but they were reclassified as pending loads in the 2025 GNA/DUPR and thus not included in the 2025 metrics. This must be considered if one is trying to observe changes/trends in known loads over time. The data that was removed amounted to approximately 900 known loads with a total MVA value of approximately 800 MVA. The analysis below was structured to eliminate errors due to this change in the classification of Vendor Forecasts.

Some observations regarding the data and metrics provided by SCE are as follows:

1. From the data in Table 2-5 we see that there has been significant overall growth in total known loads in the 10-year planning period in the 2024 cycle to the 2025 cycle. We have included data for Total known loads and three categories of known loads which are the larger and growing categories – namely, Commercial, Residential and Transportation known loads.
2. The overall number of known load projects grew from 3125 to 3342 (a 7% increase) and the MVA has increased from 4114 to 5685, or by 38%.
3. The number of Commercial and Residential KLs has grown by 1% and 22% respectively and their total MVA has grown by 35% and 56%.

4. The number of TE KLs has grown by 11% and their total MVA has grown by 52%. That amounts to a nearly 600 MVA increase from the 2024 cycle to the 2025 cycle.
5. The growth in amounts (MVA) in all categories in the table was proportionally much higher than the growth in the number of KLs (counts).
6. The total amount in MVA of load deferral over the planning period was 1274 MVA in 2025 which is about 9% higher than in the last cycle.
7. Deferral rates for the TE load categories were 44% compared to 57% in the last cycle. For the two TE categories, LD EV charging, and MD/HD EV Charging their respective growth rates were 44.1% and 451.6% respectively in this cycle.
8. Total cancellation rate in 2025 is 9.8% compared to 10% in the last cycle and cancellation rates for the TE load type - is 16.4% compared to 4.6% in the last cycle a nearly fourfold increase. Cancellation rates for individual TE categories were 18.6% for LD EV charging and 12% for MD/HD EV Charging.

Table 2-4: Know Load Tracking Data Comparison

	2024	2025	Change from '24 to '25 - %
Total			
KL MVA	4114	5685	38.2%
KL Count	3125	3342	6.9%
Cancelled %	10	9.8	-2.0%
Deferred MVA	1166	1274	9.3%
Deferred %	55.7	35	-37.2%
Commercial			
KL MVA	1322	1781	34.7%
KL Count	1234	1248	1.1%
Cancelled %	1.5	8	433.3%
Deferred %	69.7	5.6	-92.0%
Residential			
KL MVA	751	1171	55.9%
KL Count	840	1022	21.7%
Cancelled %	0.9	5.8	544.4%
Deferred %	57	14.5	-74.6%
Transportation			
KL MVA	1265	1920	51.8%
KL Count	600	664	10.7%
Cancelled %	4.6	16.4	356.5%
Deferred %	57.4	44.1	-23.2%

2.2.3. Analysis of Known Load Data

The IPE analyzed the 2023, 2024 and 2025 Known Load Tracking data to assess whether loads that were forecast to be served in each of those years materialized as forecasted. This was done using three separate data analyses (one for each year-2023, 2024 and 2025). The analysis estimated how many known loads that were forecasted to be realized in each of those years were shown as actually completed in that year or were deferred to a future year. The result of that analysis is shown in the tables below. The results for 2023 and 2024 are tables that come from the 2024 DPAG Report; the 2025 results are new.

From the table we see that 86% of the known loads forecast to be completed in 2023 were either completed or deferred to later years. Of the known loads that were forecast to be completed in 2024, 73% were either completed or deferred. Thus, the materialization rate shows a slight downward trend in 2024 compared to 2023. Projects that were actually completed in 2023 and 2024 were 655 (53%) and 347 (29%) respectively.

Table 2-5: Analysis of 2023 and 2024 Tracking Data

Analysis of 2023 Known Load Tracking Data		Analysis of 2024 Known Load Tracking Data	
Total Number of Known Loads (KL) Planned for Service in 2023 in 2022 KL Data	1216	Total Number of Known Loads (KL) Planned for Service in 2024 in 2023 KL Data	1213
Number of KL Completed in 2023	655	Number of KL Completed in 2024	347
Number of KL Effectivley Defered to a later date in the Planning Period	385	Number of KL Effectivley Defered to a later date in the Planning Period	542
Total Number of KL Completed or Deferred	1040	Total Number of KL Completed or Deferred	889
Percent of KL Completed or Deferred out of Total Planned for Service in 2024	86%	Percent of KL Completed or Deferred out of Total Planned for Service in 2024	73%

The same materialization analysis was performed with the 2025 tracking data for all known loads and for transportation electrification known loads. The result for all known loads is shown in the following table. We see that the materialization rate of 78% is slightly better than 73% rate in the last cycle.

Table 2-6: Analysis of All 2025 Tracking Data

Analysis of All 2025 Known Load Tracking Data	
Total Number of Known Loads (KL) Planned for Service in 2025 in 2024 KL Data	1826
Number of KL Completed in 2024	222
Number of KL Effectivley Deferred to a later date in the Planning Period	1009
Total Number of KL Completed or Deferred	1422
Percent of KL Completed or Deferred out of Total Planned for Service in 2025	78%

The IPE also developed materialization ratios for 2023 and 2024 for Transportation Electrification known loads in its IPE Post DPAG report Published in March of 2025. The tables below are from that report. We see from those tables that the TE materialization factors are lower than for all known loads and for these two years has a downward trend (from 79% to 68%)

Table 2-7: Analysis of TE 2023 and 2024 Tracking Data

Analysis of 2023 Known Load Tracking Data - LD & MD/HD EVs		Analysis of 2024 Known Load Tracking Data - LD & MD/HD EVs	
Total Number of Known Loads Planned for Service in 2023 in the 2022 KL Data	172	Total Number of Known Loads Planned for Service in 2024 in 2023 KL Data	277
Number of KL Completed in 2023	81	Number of KL Completed in 2024	101
Number of KL Effectivley Deferred to a later date in the Planning Period	55	Number of KL Effectivley Deferred to a later date in the Planning Period	86
Total Number of KL Completed or Deferred	136	Total Number of KL Completed or Deferred	187
Percent of KL Completed or Deferred out of Total Planned for Service in 2023	79%	Percent of KL Completed or Deferred out of Total Planned for Service in 2024	68%
Total Number of Cancellations of KL Planned for service in 2023	35	Total Number of Cancellations of KL Planned for service in 2024	92
Cancellations of KL Planned for service in 2023 in Percent	20%	Cancellations of KL Planned for service in 2024 in Percent	33%

The IPE also analyzed 2025 TE known load tracking data with the result shown in the table below. We see that the materialization rate of 77% is better than the 68% in 2024.

Table 2-8: Analysis of TE 2025 Tracking Data

Analysis of TE 2025 Known Load Tracking Data	
Total Number of Known Loads (KL) Planned for Service in 2025 in 2024 KL Data	517
Number of KL Completed in 2024	54
Number of KL Effectively Deferred to a later date in the Planning Period	343
Total Number of KL Completed or Deferred	397
Percent of KL Completed or Deferred out of Total Planned for Service in 2025	77%

Completion Rate Trend

From the previous data we see that project completions seem to be decreasing. Completion rates were calculated for all known loads and the TE known loads. These rates are tabulated in Table 2-10 and they show that rates have generally decreased over time for all known loads and for TE known loads have consistently decreased over that time period. We plan to review this data to determine if there is an underlying cause and include our results in the IPE Post DPAG Report.

Table 2-9: Completion Rates

Total	2023	2024	2025
Count of All KL	1216	1213	1826
Count of Completed KLS	255	347	222
Completion Rate %	21.0%	28.6%	12.2%
Transportation			
Count of All KL	172	277	517
Count of Completed KLS	81	101	54
Completion Rate %	47.1%	36.5%	10.4%

2.2.4. Utility Owned DER Projects

According to its filing, SCE did not evaluate SCE-owned DERs as solution alternatives in conjunction with traditional wires solutions as part of its 2025 DPP. SCE is still working through internal processes, software capabilities, technical training, and evaluation methodologies to enable engineers to evaluate SCE owned and operated DER as solutions within its DPP.

SCE intends to evaluate SCE-owned DERs as solutions in future planning processes and expects the level of integration to be iteratively improved over time as methods, software, and processes are further developed.

2.2.5. Line Segment Needs

SCE did not include needs at the line segment level in its GNA/DUPR. SCE is currently developing systems to facilitate the development of such line segment needs.

2.3. GNA - Observations, Conclusions and Recommendations

- We observe the number of needs in this cycle is significantly greater than the previous cycle by 69% and by about 250% over the last 5 years. The number of known loads is also significantly greater than the previous cycle by 38%; known and pending loads have grown about 300% over the last five years.
- We observe that SCE has developed a well thought out methodology to calculate the Known Load Tracking Metrics and presented a full set of metric results for the past three cycles.
- We observe that the materialization factor for All known loads and TE known are better than last cycle's values.
- We observe that 2025 tracking data metrics shows that 2025 completions are down, and deferrals are up compared to 2024. Overall cancellations are about the same but are up for Commercial, Residential and Transportation.
- We observe that because of the change to the Borrow Forward method for processing embedded known loads that the embedded known load metrics have increased in importance because these types of known loads (embedded) are no longer constrained by the annual IEPR load forecasts. Instead, they are included in the DPP in a similar manner to the way incremental known loads are. Therefore, whether they materialize is now a more important question.
- We observed in our 2022 SCE IPE DPAG Report that in the past and including the last DIDF cycle that SCE has provided information for its incremental known load projects based upon information provided by its customers which captured peak needs, which in some cases does not consider the diversity of the customers' loads. To capture the potential for the customer's load diversity, SCE applies a discount factor (a value of less than 1.0) to the peak load data provided by the customer. This value varies depending upon the amount of information provided by the customer but generally ranged from 0.75 to 1.0 in the last cycle. On average, for the previous cycle, this discount factor was approximately 0.80 for embedded and incremental known loads. For each known load, the peak value is appropriately adjusted for customer diversity by reducing the peak value by multiplying it by the discount factor before using in the DPP.

We observe that by reporting known load values in the GNA/DUPR prior to adjusting

for customer diversity the known load value may appear larger in the GNA/DUPR than the load value actually used in the DPP by about 20% (1.0 - 0.8). SCE provided the IPE with the discount factors for all of the known loads (embedded and incremental) used in the current DPP cycle.

- As performed in the previous cycle, the IPE plans to review the Known Load Metrics for all three IOUs in its Post-DPAG Report to be completed in March 2026, i.e., the 2026 Post-DPAG report with a focus on Known Load materialization. It is important to understand whether Known Loads materialize considering data from multiple years, since they are an important component of the distribution planning process.
- The IPE recommends that, in addition to the Known Loads, the IOUs annually track Pending Loads similar to Known Loads since these loads could have similar impacts to Known Loads. The IPE also recommends that, in addition to the Known Load metrics, metrics for Pending Loads be calculated similar to those for Known Loads. Further, these metrics should be separately calculated for each Pending Load category (A, B, C etc.). In addition, combined metrics for all the loads used in planning, (i.e., Known Loads and Pending Loads that were used in the Base Case) should also be calculated. The exact format for reporting the Pending Load data and the metrics that need to be calculated should be jointly developed by the Energy Division and the IOUs.
- The IPE recommends that the Pending Loads identified using studies be updated periodically (ideally, annually) and that the source (i.e., customer study name) be provided in the Pending Load tracking data mentioned above.
- The IPE would like to reiterate the recommendation made in the last cycle (2025 Post-DPAG Report) that the IOUs calculate system-level, as well as a TE-specific materialization metrics similar to what the IPE has calculated in the 2025 Post-DPAG report and include these new metrics in the GNA/DUPR report.
- The IPE would also like to reiterate the recommendation made in the last cycle that the Commission suspend the requirement for calculating Known Loads Metrics 14-16 related to service deferral, cancellation and reduction rate by forecast year since these metrics have shown limited value.
- The IPE plans to review and compare in the 2026 Post-DPAG report, the methodologies used by the IOUs to confirm that planned projects identified in prior cycles are still needed and are the appropriate solution based upon planning assumptions for load and DER growth and other planning assumptions used in the current DPP cycle. The IPE gathered some information as a part of Step 13 in this cycle and will use this information, as well as other information gathered from the utilities to perform this review.

3. Review of DUPR Report

Listed below is a high-level summary of the SCE DUPR Report that was filed on August 15, 2025. The DUPR Report includes descriptive material in PDF format and an Excel file which contains the data for planned investment and planned solutions, if any.

DUPR Report

The 2025 SCE DUPR report includes a narrative along with an Excel-based workbook containing two sheets: “Planned Investment (Funded)” and “Planned Solutions”. The data reflected in the workbook represents a portion of SCE’s traditional infrastructure projects that contribute to the operation of the distribution system and in the past served as the baseline for evaluating opportunities for DERs to potentially defer or avoid traditional distribution system investments. However, since the CPUC has paused deferral aspects of the DIDF for this cycle, the project DUPR information serves primarily an informational role. The DUPR does contain SCE’s planned investments which address the grid needs identified in the GNA report. Only those planned investments that have gone through relevant internal approval processes and have been allocated budget through the DPP are included in the DUPR as planned investments. This ensures that the planned investments included in the DUPR have a reasonable expectation of being constructed.

DUPR Planned Investments and Planned Solutions

Shown in the following table are the Planned Investments included in SCE’s DUPR report. The total number of planned investments in the 2025 DUPR is 574 projects which compares to 441 planned investments in the 2024 DUPR for a substantial increase of about 28%. The tables show that a large number of the projects are in the Metro and Metro West and are predominantly distribution capacity projects in nature. Other data in the DUPR Report indicates that 88% of the planned investments have an operating date in the first three years of the planning period compared to 71% in 2024 and 88% in 2023.

Table 3-1: 2024 and 2025 Planned Investments by Type

2024 Planned Investments

Region	Project Type			Voltage
	Distribution	Distribution VAR	Subtransmission	
Desert Region	45	6	18	69
Metro East Region	68	20	14	102
Metro West Region	59	6	4	69
North Coast Region	43	14	15	72
Orange Region	39	14	4	57
Rurals Region	17	4	3	24
San Jacinto Region	16	7	3	26
San Joaquin Region	16	2	4	22
Total	303	73	65	441

2025 Planned Investments

Region	Project Type			
	Distribution	Distribution VAR	Subtransmission	Total
Desert Region	69	8	14	91
Metro East Region	95	12	15	122
Metro West Region	80	9	6	95
North Coast Region	26	5	4	35
North Valley Region	37	6	7	50
Orange Region	35	11	6	52
Rurals Region	34	10	0	44
San Jacinto Region	33	8	4	45
San Joaquin Region	36	0	2	38
Total	445	69	60	574

Table 3-2: 2024 and 2025 Planned Investments by Year

2024 Planned Investments

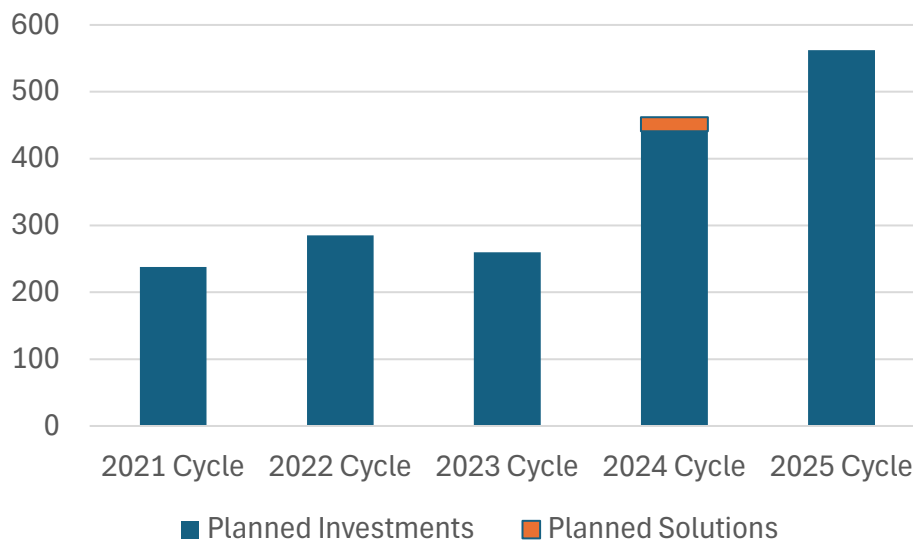
Operating Date										
2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
75	158	82	79	45	1	1	0	0	0	441

2025 Planned Investments

Operating Date					
2025	2026	2027	2028	2029	Total
143	187	141	52	36	559

In Figure 3-1 the number of planned solutions and investments is plotted for each of the past 5 cycles. From the plot we see that the number of planned solutions and investments shows a growth totaling 220% over the five-year period.

Figure 3-1: Planned Solutions and Investments by Cycle



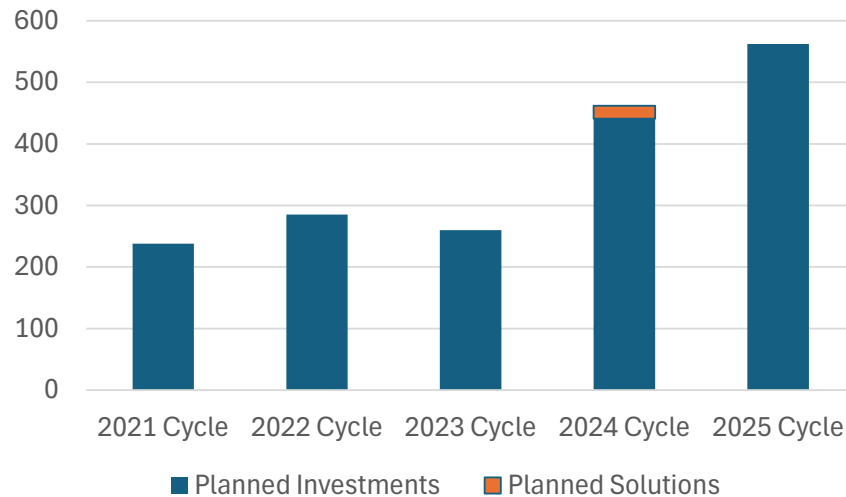
Project Prioritization

In the past cycles SCE included projects in the DUPR that had a reasonable chance of being funded as planned investments. In the last cycle, SCE also included projects, known as planned solutions, which were driven by needs in the GNA but were not likely to be funded according to the results of SCE's most recent GRC or other capital planning processes. In this current cycle, however, there are no planned solutions included in the DUPR.

SCE uses a screening process to determine which projects were considered planned solutions and which should be funded as planned investments. SCE indicated that they considered these (and other factors) in their prioritization - the magnitude of risk/need,

whether or not customer energization was dependent upon the investment, budget availability, planning and construction resources, regional resources, supply chain availability, age of infrastructure, and whether there were any overlaps with other SCE distribution programs. SCE's prioritization process is reviewed in Section 5.5.6 as part of the review of Step 27.

Figure 3-2: Planned Solutions and Investments by Cycle



3.1. DUPR Report Planned Investments - Observations, Conclusions and Recommendations

- We observe that the number of planned projects in the past five cycles has increased significantly - roughly 220% over that period. This is consistent with the increase in the number of needs in the GNA and the number of known load projects.
- Based upon discussions with SCE, this significant growth in projects will require a substantial scaling up of resources to complete these projects in time to meet customers requested in-service dates.

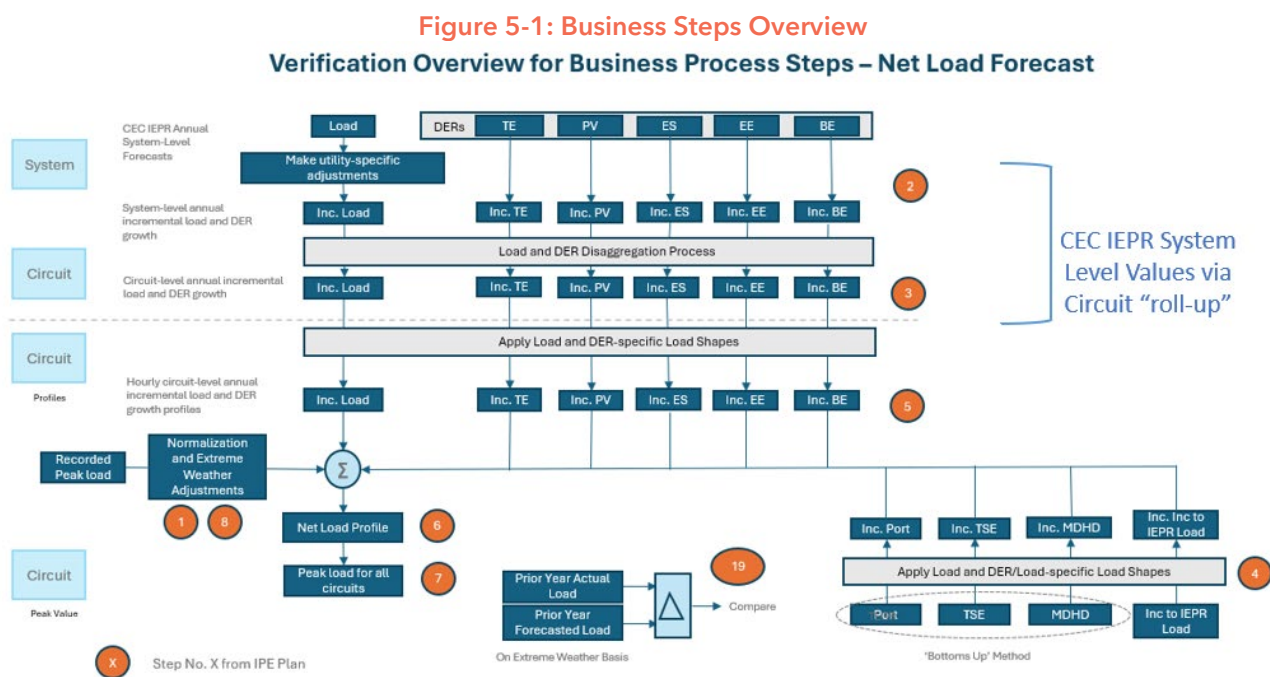
4. Other Items of Interest

4.1. Miscellaneous - Observations, Conclusions and Recommendations

None at this time.

5. Verification Approach and Results

In this section we will discuss the verification approach used, and the results achieved for the steps identified in the IPE Plan for this cycle. This verification review will follow the framework set out in the Final IPE Plan included in Appendix C. The following graphic provides a high-level overview of Steps 1 through 8 and 19 in the review process. Note: the graphic does not reflect that there is an impact from SCE's TOU Metering which is included in the forecast business process but not in the graphic. Note the graphic includes steps that were not included in this cycle's IPE V&V process as described in Section 1.



5.1. PROCESSES TO DEVELOP SYSTEM LEVEL FORECASTS AND DISSAGREGATE TO CIRCUIT LEVEL

5.1.1. Collect 2024 Actual Circuit Loading, Normalize and Adjust for Extreme Weather - Steps 1 and 8

This step reviews part of the process that SCE uses to develop the starting point of the forecasting process which includes collecting actual circuit loading profile data, normalize it

to an average year (referred to as a 1 in 2 value) and adjusting it to an extreme weather year (referring to a 1 in 10 year).

SCE uses a Typical Meteorological Year (TMY) based methodology to generate normalized (1-in-2) temperature data to be used for forecasting future load in forecasting models. These loads are referred to as Normal Projected Load.

The three-step process used is summarized below:

1. Monthly long term energy models run multiple linear regression (statistical) models that:
 - Associate historical monthly energy (MWh) as the dependent variable with different sets of candidate independent variables, such as:
 - macroeconomic driver (e.g., multifamily housing starts, real personal income, etc.) dummy variables for month of year, load transfers, etc.
 - weather data (cooling degree days and heating degree days)
2. Regression model produces parameter estimates that describe the historical relationship between monthly energy and the independent variables.
3. Estimated MWH for the month would be the sum-product of the parameter estimates with the values of the historical independent variables.

Figure 5-2 shows graphically the process used to develop 1-in-2 loads.

Figure 5-2: Overall Process to Develop 1 in 2 Loads

1-in-2 Typical Meteorological Year (TMY) Normalization¹

1. Long-term monthly energy models use multiple linear regression to model historical monthly energy (MWh) consumption as the dependent variable, using different sets of candidate **independent variables**, such as:

- macroeconomic driver (e.g., multifamily housing starts, real personal income, etc.)
- dummy variables for month of year, load transfers, etc.
- weather data (cooling degree days and heating degree days²)

2. Regression model produces **parameter estimates** that describe the historical relationship between monthly energy consumption and the independent variables.

3. **Monthly energy estimates** are derived as the **sum-product of the regression parameter estimates and the corresponding values of the independent variables**.

Example for TMY Normalization

Parameter Name	Parameter Value	Actual Values of Independent Variables (in July 20XX)	= (Parameter Value) x (Actual Values of Independent Variables) (in July 20XX)
Intercept	0.035	1	0.035
dJan	-0.6	0	0
dFeb	-0.5	0	0
dMar	0.05	0	0
dApr	0.1	0	0
dMay	0.3	0	0
dJun	0.4	0	0
dJul	0.55	1	0.55
dAug	0.51	0	0
dSep	0.23	0	0
dOct	-0.04	0	0
dNov	-0.05	0	0
RealPerCapitalIncome	2.12	11	23.32
CoolingDegreeDays	1.2	4.3	5.16
HeatingDegreeDays	0.045	0	0
Estimate MWH for July 20XX			29.065

1. Based on the TMY methodology proposed by Sandia National Laboratories: Zang, Haixiang & Wang, Miaomiao & Huang, Jing & Wei, Zhinong & Sun, Guoqiang. (2016). A Hybrid Method for Generation of Typical Meteorological Years for Different Climates of China. Energies. 9. 1094. 10.3390/en9121094.

SCE calculates 1-in-10 load values referred to as Critical Projected Load using a formula shown graphically in Figure 5-3.

Figure 5-3: Critical Projected Load Adjustment

The Normal Projected Load based on TMY conditions is adjusted to reflect a 1-in-10 year extreme temperature scenario (a.k.a., Criteria Projected Load¹), based on historical customer electricity usage patterns, in a specific geographic region, correlated with observed temperature variations.

$$\text{Criteria Projected Load} = \text{Normal Projected Load} \times \left(1 + \frac{\text{Design Reserve Factor}}{100} \right)$$

For Summer Peaking

Design Reserve Factor (DRF) = Temperature Range * Temperature Sensitivity



For Winter Peaking² (Not Temperature Sensitive)

DRF = Operating DRF (User Input)

Typically 10%

1. Within SCE, Extreme Weather Load is internally referred to as "Criteria Projected Load".
2. More specifically, winter peaking includes non-summer seasons (Fall, Winter, Spring).

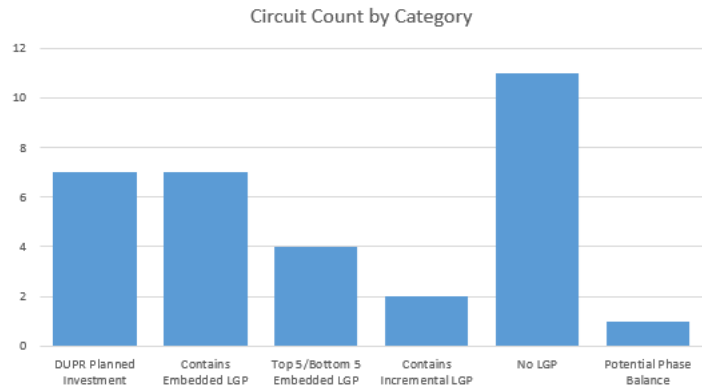
We can see from the graphic that the adjustment is a function of the Design Reserve Factor (DRF), which is a function of location in the SCE system. The location of an asset influences the DRF since the temperature used in calculating the DRF comes from the closest weather station or best geographical representation of the asset.

As part of the IPE verification process, working with SCE, the IPE selected 20 circuits to be used as appropriate for various steps in the review process. The circuits and their characteristics (whether they were associated with planned investment, were candidate deferral projects, included embedded or incremental known load adjustments, etc.) are tabulated in Figure 5-4 below. The objective was to choose a subset of circuits that could be used in the verification of many of the IPE defined business steps.

Figure 5-4: 20 Selected Circuits for use in IPE Verification

Selected 20 Circuits Overview

Circuit	Substation	Region
Toga	Haskell 66/16 (D)	North Valley Region
Osner	Delano 66/12 (D)	San Joaquin Region
Anaconda	North Oaks 66/16 (D)	North Valley Region
Gold	Limestone 66/12 (D)	Orange Region
Sid	Rialto 33/12 (D)	Desert Region
Gordon	Rector 66/12 (D)	San Joaquin Region
Sundance	Sun City 115/12 (D)	San Jacinto Valley Region
Beagle	Moulton 66/12 (D)	Orange Region
Bison	Lampson 66/12 (D)	Orange Region
Kenoak	Pomona 12/4.16 (D)	Metro East Region
Nemaha	Layfair 66/4.16 (D)	Metro East Region
Rockwell	Tennessee 66/12 (D)	Desert Region
Sopwith	Stetson 115/12 (D)	San Jacinto Valley Region
Bacon	Imperial 66/4.16 (D)	Metro West Region
Turkey	Ordway 33/12 (D)	Rurals Region
Bean	San Gabriel 66/4.16 (D)	Metro East Region
Blackhawk	Shawnee 66/12 (D)	Orange Region
Blueberry	Citrus 66/12 (D)	Metro East Region
Cereal	Skylark 115/12 (D)	San Jacinto Valley Region
Duncan	South Gate 16/4.16 (D)	Metro West Region

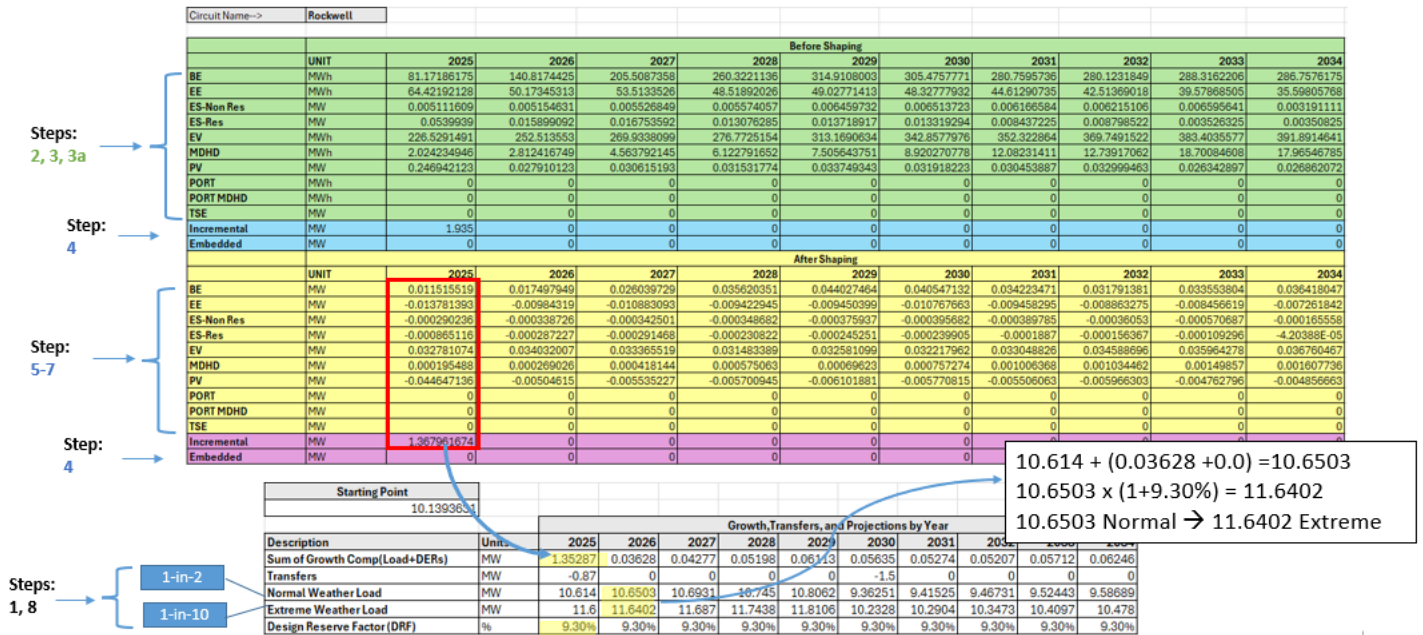


SCE used the workbook shown in Figure 5-5 to demonstrate how the 1 in 2 and 1 in 10 values are developed. The workbook was capable of examining the data for all 20 circuits selected earlier. The data shown in the figure is for the Rockwell circuit.

Figure 5-5: Demo for Steps 1, 4 and 8

20 Circuit Data

- Interactive Demonstration ([Dynamic Sheet](#) contains dropdown driven data for 20 circuits)



5.1.2. Determine Load and DER Annual Growth on System Level - Step 2

This step reviews the development of utility specific system level values of load and DER growth from the CEC IEPR data. In the case of SCE these values are energy values, since SCE uses system level energy values at this part of the overall planning process. Shown in Figure 5-6 are the CEC data sets and scenarios used by SCE in this step and a comparison of what was used in this cycle to what was used in the last cycle. All three utilities used a set of data and scenarios for their companies that correspond to the set SCE used. These data sets and scenarios were presented to the Distribution Forecast Working Group for review.

Figure 5-6 : CEC IEPR Data Sets used by SCE in 2024 and Disaggregation Differences

IEPR Forecasts and Scenarios Comparison

2024-2025 GNA/DUPR Cycle

		2024-2025 GNA/DDOR Cycle		
		SCE	PG&E	SDG&E
CEC-Adopted IEPR Vintage		2022 IEPR Local Reliability Scenario	2022 IEPR Local Reliability Scenario	2022 IEPR Local Reliability Scenario
Forecast	Economic, Demographic, and Price Scenarios	Baseline (Mid)	Baseline (Mid)	Baseline (Mid)
	Additional Achievable Energy Efficiency (AAEE)	Low (Scenario 2)	Low (Scenario 2)	Low (Scenario 2)
	Additional Achievable Fuel Substitution (AAFS)	High (Scenario 4)	High (Scenario 4)	High (Scenario 4)
	Additional Achievable Transportation Electrification (AATE)	Mid (Scenario 3)	Mid (Scenario 3)	Mid (Scenario 3)
	CARB SIP zero emission space and water heating equipment sales after 2030	Included	Included	Included

2025-2026 GNA/DPUR Cycle

		2024-2025 DPP Cycle (2025 GNA)		
		SCE	PG&E	SDG&E
CEC-Adopted IEPR Vintage:		2023 IEPR Local Reliability Scenario	2023 IEPR Local Reliability Scenario	2023 IEPR Local Reliability Scenario
Forecast Elements	Economic, Demographic, and Price	Baseline	Baseline	Baseline
	Additional Achievable Energy Efficiency (AAEE)	Scenario 2	Scenario 2	Scenario 2
	Additional Achievable Fuel Substitution (AAFS) ⁽¹⁾	Scenario 4	Scenario 4	Scenario 4
	Additional Achievable Transportation Electrification (AATE)	Scenario 3	Scenario 3	Scenario 3

The Excel spreadsheet in Figure 5-7 shows how SCE used CEC IEPR data to develop system level load energy growth, for use in developing annual energy delivered over its distribution system, which is then used in the distribution planning process.

Figure 5-7: Process to Develop System Load Growth

Load Disaggregation (System)

Pre-Disaggregation Load Adjustments Used to Prevent Double Counting

Step	SCE IEPR T&C Load (MWh)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Source
1	Total Consumption (includes TE and Climate Change)	110,066,120	111,669,125	112,944,673	114,393,901	116,212,836	118,169,833	120,169,073	122,183,563	124,181,658	126,110,541	128,047,454	2023 IEPR: Energy Demand Forecast Form 1.2
2	EV, Other Electrification	1,914,985	2,722,549	3,564,177	4,490,017	5,538,458	6,705,484	7,965,853	9,298,780	10,589,285	11,773,031	12,952,887	2023 IEPR: "TE Summary" tab line 5
3	Total Consumption (without TE)	108,151,135	108,946,575	109,380,495	109,903,884	110,674,378	111,464,349	112,203,220	112,884,783	113,592,373	114,337,511	115,094,567	Calculation (Step 1 minus Step 2)
4	Inc. Growth (MWh)		795,439	433,920	523,389	770,494	789,971	738,871	681,564	707,590	745,138	757,056	Calculation (Annual Incremental of Step3)
Step	Other Growth (MWh)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Source
5	Anaheim, City of	2,170,877	2,185,232	2,197,854	2,219,318	2,251,804	2,294,749	2,340,394	2,389,168	2,440,473	2,507,072	2,580,581	2023 IEPR: Form 1.1C
6	Arco Electric Cooperative, Inc.	67,684	67,860	68,332	69,130	70,470	72,117	73,861	75,505	77,490	79,849	82,350	
7	Arco's Light and Water	237,512	238,053	238,750	240,553	243,692	247,950	252,688	257,891	263,645	269,935	276,874	
8	Banning, City of	144,258	145,514	146,927	148,940	151,842	155,262	158,782	162,415	166,433	171,376	176,653	
9	Beir Valley Electric Service	129,372	129,410	129,571	130,398	132,137	134,385	136,664	139,265	142,062	146,124	150,763	
10	Cerritos, City of	69,324	69,740	70,159	70,580	71,003	71,429	71,858	72,289	72,723	73,159	73,598	
11	Colton Public Utilities	341,123	342,392	343,057	345,082	348,814	353,419	357,954	363,433	369,128	377,795	387,870	
12	Corona, City of	137,003	137,866	138,224	139,000	140,139	141,277	142,290	143,525	144,670	146,594	148,929	
13	Eastside Power Authority	28,190	28,306	28,300	28,397	28,541	28,645	28,714	28,799	28,879	29,023	29,204	
14	Industry, City of	40,360	40,980	41,503	42,091	42,789	43,659	44,511	45,536	46,492	47,790	49,186	
15	Moreno Valley Electric Utility	209,737	213,336	216,389	220,245	225,116	230,695	236,313	242,434	248,574	256,438	264,834	
16	Pasadena Water and Power	1,029,410	1,037,711	1,046,279	1,058,952	1,077,457	1,102,074	1,128,388	1,156,489	1,186,070	1,224,273	1,266,365	
17	Rancho Cucamonga Municipal Utility	99,242	100,111	100,332	100,905	101,925	103,192	104,426	106,012	107,582	110,157	113,194	
18	Riverside, City of	2,151,251	2,178,536	2,203,485	2,237,253	2,282,457	2,334,583	2,387,451	2,443,372	2,501,948	2,575,529	2,653,933	
19	Vernon, City of	1,110,859	1,117,069	1,117,901	1,122,822	1,129,878	1,137,374	1,143,641	1,151,937	1,159,035	1,169,423	1,180,547	
20	Victorville Municipal Utility Services	103,711	104,139	104,120	104,473	105,006	105,387	105,643	105,954	106,230	106,778	107,443	
21	Incremental Other Growth (MWh)	8,009,915	8,136,256	8,191,183	8,278,138	8,403,070	8,556,197	8,713,579	8,883,523	9,060,451	9,290,716	9,542,324	Calculation (Summation of Step 5 to Step 20)
Final incremental load growth values for the DSP at SCE system level													
Step	MWh	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Source
22	SCE Cumulative System Total Consumption	100,081,221	100,810,320	101,189,313	101,625,746	102,271,308	102,908,152	103,489,641	104,001,261	104,531,921	105,046,795	105,552,243	Calculation (Step 3 minus Step 21)
23	SCE Incremental System Load Growth		729,099	378,993	436,433	645,562	636,944	581,489	511,620	530,661	514,874	505,448	Calculation (Annual Incremental of Step 22)

The notes on the right of the table provide details about the spreadsheet calculations. The data at the top of the table is reduced by the load not served by SCE (shown in the middle of the table) and a net annual energy growth in MWh is calculated and shown online.

Calculations were performed to develop annual energy growth at the system level in SCE service territory based upon CEC IEPR data for Energy Efficiency (EE), Transportation Electrification, Photovoltaics (PV), and Energy Storage (ES),

These values are then used, along with the starting points, to develop a load forecast for load and DERs in subsequent process steps. The IPE verified the calculation and the fact these values were used in the disaggregation process as input in subsequent steps of the overall load forecasting process.

The IPE verified Step 2 as discussed above through a combination of demos performed by SCE and data analysis performed by the IPE.

5.1.3. Disaggregate Load and DER Annual Growth to the Circuit Level - Step 3

In this step SCE demonstrated how system level values compare to the corresponding aggregate of all circuit level values. In the figure below we see a comparison of the system level IEPR Energy based upon LGP values to the sum of the allocated values that shows they are identical.

Figure 5-8: Check of System Level EV Load Growth vs. Sum of All Circuit EV Load Growth

Load Disaggregation (System vs. Circuit)

Comparison of System Forecasted Values to Aggregate of Disaggregated Circuit Values

Steps	Source File	Flow Execution	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	
1	External IEPR Forecast (MWh)	Cumulative Year Over Year (16 Years)	100081220.8	104831283.6	108345568.3	110273288.8	111473146.3	111945027.5	112276217.4	112466516.5	112618326.8	112723908.7	112759673.7	IEPR Energy based on LGP Energy
		Annual Incremental	0	4750062.84	3514284.61	1927720.54	1199857.52	471881.15	331189.90	190298.89	151810.30	105581.93	35764.94	
2	SCE LGP Embedded (MWh)	A-Source	0	4750058.41	3514282.40	1927718.48	1199856.32	471880.71	331189.54	190298.89	151810.09	105581.79	35764.94	
		B-Source	0	0	0	0	0	0	0	0	0	0	0	
		C-Source	0	0	0	0	0	0	0	0	0	0	0	
		Total (A + B + C)	0	4750058.41	3514282.40	1927718.48	1199856.32	471880.71	331189.54	190298.89	151810.09	105581.79	35764.94	
3	Allocate Econ Driver (MWh)	Allocate A	0	4750062.84	3514284.61	1927720.54	1199857.52	471881.15	331189.90	190299.11	151810.30	105581.93	35764.99	
		Allocate B	0	0	0	0	0	0	0	0	0	0	0	
		Allocate C	0	0	0	0	0	0	0	0	0	0	0	
		IEPR - Total LGP (A + B + C)	0	4.43	2.21	2.05	1.20	0.45	0.35	0.22	0.20	0.14	0.05	
4	Borrow Forward Methodology	A-Factor	0	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	Energy Allocated matches Energy Input
		B-Factor	0	0	0	0	0	0	0	0	0	0	0	
		C-Factor	0	0	0	0	0	0	0	0	0	0	0	

The IPE verified Steps 3 and 3a as described above through a combination of demos performed by SCE and analysis of selected values performed by the IPE.

5.1.4. Add Incremental Load Growth Projects to Circuit Level Forecasts (those loads believed to not be in CEC forecast) - Step 4

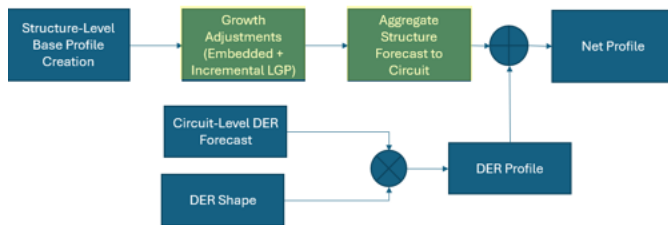
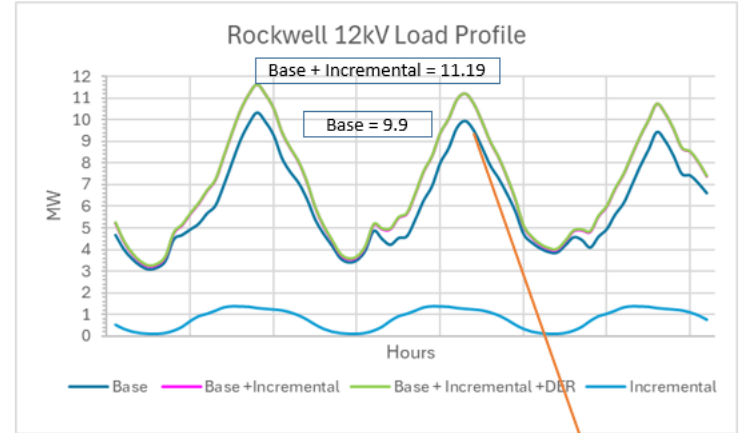
This step reviews the addition of LGPs that SCE considers load amounts over and above the load in the CEC IEPR. The loads included in 2025 which are referred to as Incremental Known Load Growth Projects and other loads that are additive to the IEPR load growth are discussed in Section 2. These include Incremental Known Loads, Vendor Forecasts, Truck Stops, Port loads and SCE fleet conversion.

In a demo for Rockwell 12 kV circuit, SCE used Figure 5-9 below to show the addition of an Incremental Known Load of 1.37 MWs to the circuit loading forecast.

Figure 5-9: Demo of Selected Circuits with a Load Growth Project

Rockwell 12kV 2025 Load Forecast

- This demonstrates how incremental loads are added to the circuit level base profile
 - Incremental Load Growth project (step 4) post shape application added to SLF base profile (step 1)
 - Zoomed in section of 2025 8760 profile in order to capture profile features



	UNIT	2025	2026	2027	2028	2029
BE	MW	0.011515519	0.017497949	0.0	0.0	0.0
EE	MW	-0.013781393	-0.00984319	-0.0	-0.0	-0.0
ES-Non Res	MW	-0.000290236	-0.000338726	-0.0	-0.0	-0.0
ES-Res	MW	-0.000865116	-0.000287227	-0.0	-0.0	-0.0
EV	MW	0.032781074	0.034032007	0.0	0.0	0.0
MDHD	MW	0.000195488	0.000269026	0.0	0.0	0.0
PV	MW	-0.044647136	-0.00504615	-0.0	-0.0	-0.0
PORT	MW	0	0	0	0	0
PORT MDHD	MW	0	0	0	0	0
TSE	MW	0	0	0	0	0
Incremental	MW	1.367961674	0	0	0	0
Embedded	MW	0	0	0	0	0

Rockwell 12kV growth projects (Incremental) for 2025 with magnitude of 1.36796 MW.

Using selected circuits, the IPE verified Step 4 through a demo of the addition of the incremental known load on the Handcar, Zebu and Tuna circuits performed by SCE and analysis performed by the IPE.

5.1.5. Convert Peak Growth to 8760 Profile, Determine Net Load and Peak Load - Steps 5, 6, and 7

This section would normally review the process used to convert the data from the previous step into profiles, combine the load and DER profiles, to develop a net-load profile and to calculate a net peak load for the circuit. According to the IPE Plan review of these steps will not be included in this cycles report.

5.2. PROCESSES TO DETERMINE CIRCUIT NEEDS AND DEVELOP GNA

5.2.1. Process to Determine Circuit Needs - Step 9-11

In this section we would normally briefly discuss the business process involved in Steps 9 through 11 that are used to determine if there is a need at the distribution or subtransmission level. Per the IPE Plan these steps are skipped in this report for this cycle.

5.2.2. Compile GNA Tables Showing Need and Timing - Step 12

This step reviews the analysis that determines if there is a grid need that requires action to be taken to address the need, the amount of the need, and the timing of the need. The GNA tables (that were filed in August) include only needs that exist after no cost solutions have been implemented. The process and calculations used to determine needs, after no cost solutions was reviewed in a previous step with examples for several need determinations, so they will not be repeated here. That review also demonstrated that the results of those reviews were reflected in the GNA/DUPR Report

5.3. PROCESSES TO DEVELOP PLANNED INVESTMENTS AND COSTS

5.3.1. Develop Recommended Solution - Step 13

This step normally reviews the entire process that SCE used to determine the appropriate planned investment to meet the needs in the GNA Report. As reflected in the approved IPE Plan, for this cycle this section will review only the portion of this process step that is used to determine if planned investments identified in a previous cycle are still needed and the project is still the appropriate solution based upon this cycle's forecast and other related planning assumptions.

The purpose of this portion of the overall Step 13 process is to 1) confirm that planned solutions and/or planned investments identified in earlier cycles are still needed and 2) to modify plans for projects that are no longer needed or whose needs have changed:

The process used to make the determination involves:

- Temporarily removing a project from the network to be analyzed. In other words, planned solutions and investments are removed from the network to be studied before the study is performed,
- Performing the assessment of the system for overloads without the project in place

- Based upon the study results, confirm if the project scope is still needed based on location, size, and current needs
- Validate whether the existing scope remains the best solution to meet the need(s)
- Adjust the scope of the planned solution or investment by determining if needs have changed and, if so, adjust the project scope accordingly (i.e. increase, decrease or change project solution design)
- Next Steps – prioritize all projects in the prioritization process described in Step 27.

SCE provided a data set for 13 projects that documented the results of this process. The data included in this data set included:

- Project DUPR ID
- Year the project was created - first included as a planned solution or investment
- Scope of the project as of the previous cycle
- Planning Year 2024 (PY 2024) Operating Date - Year that the project is planned to be completed as determined in the 2024 cycle planning assessment
- Planning Year 2025 (PY 2025) Operating Date - Year that the project is planned to be completed as determined in the 2025 (current) cycle planning assessment
- PY 2024 Deficiency in (MW, MVAR or VPU for five planning years
- PY 2024 Deficiency in % for five planning years
- PY 2025 Deficiency in (MW, MVAR or VPU for five planning years
- PY 2025 Deficiency in % for five planning years

SCE demonstrated this process for ten projects using the data listed above. The demo used the following types of slides. Shown in the first figure (Figure 5-10) below are three examples for distribution projects followed by a figure (Figure 5-11) for three for sub-transmission projects. The first example is a distribution project that was created in 2024 that is still needed based upon the most recent assessment but can be delayed (has a later Operations Date (OD) since the need occurs later than in the previous cycle. The next is an example of a project that is accelerated and enlarged to meet a larger and earlier need than reflected in the earlier cycle. The last distribution example is a project that is still needed, and the OD has not changed so no change in timing or scope is needed.

Figure 5-10: Distribution Examples for Step 13 Process

Distribution Project Development

DDOR_2020_8293	Year Created	2020											
PY 2024	Deficiency (MW, MVAR or VPU)						Deficiency %						
OD Date	2024 ^A	2025 ^A	2026 ^A	2027 ^A	2028 ^A	Units	2024 ^B	2025 ^B	2026 ^B	2027 ^B	2028 ^B		
12/31/2024	1.42	1.42	1.42	1.42	1.52	MW	31.00%	31.00%	31.00%	31.00%	33.19%		
PY 2025	Deficiency (MW, MVAR or VPU)						Deficiency %						
OD Date	2025	2026	2027	2028	2029	Units	2025 ^B	2026 ^B	2027 ^B	2028 ^B	2029 ^B		
12/31/2025	0.00	1.42	1.52	1.52	1.62	MW	0.00%	31.00%	33.19%	33.19%	35.37%		

DDOR_2020_8293

Project Scope: Linden 12/4.16 (D): Replace
4kV Switchrack Disconnect Switch

Example Type:

- Project is still needed
- Delayed/Deferred

DDOR_2022_8469	Year Created	2022											
PY 2024	Deficiency (MW, MVAR or VPU)						Deficiency %						
OD Date	2024 ^A	2025 ^A	2026 ^A	2027 ^A	2028 ^A	Units	2024 ^B	2025 ^B	2026 ^B	2027 ^B	2028 ^B		
6/1/2026	0	0	0	0.26	1.52	MW	0.00%	0.00%	0.00%	2.17%	12.71%		
PY 2025	Deficiency (MW, MVAR or VPU)						Deficiency %						
OD Date	2025	2026	2027	2028	2029	Units	2025 ^B	2026 ^B	2027 ^B	2028 ^B	2029 ^B		
6/1/2025	0.00	0.00	5.02	7.52	7.52	MW	0.00%	0.00%	41.97%	62.88%	62.88%		

DDOR_2022_8469

Project Scope: Valley 115/12 (D) –
New DSP circuit #11 and Substation Capacity

Example Type:

- OD date accelerated
- Capacity added

DDOR_2024_546050	Year Created	2023											
PY 2024	Deficiency (MW, MVAR or VPU)						Deficiency %						
OD Date	2024 ^A	2025 ^A	2026 ^A	2027 ^A	2028 ^A	Units	2024 ^B	2025 ^B	2026 ^B	2027 ^B	2028 ^B		
6/1/2025	0.05	0.08	0.11	0.18	0.25	MW	1.92%	3.17%	4.75%	7.29%	10.50%		
PY 2025	Deficiency (MW, MVAR or VPU)						Deficiency %						
OD Date	2025	2026	2027	2028	2029	Units	2025 ^B	2026 ^B	2027 ^B	2028 ^B	2029 ^B		
6/1/2025	0.39	0.26	0.31	0.37	0.43	MW	16.21%	10.80%	12.71%	15.25%	18.12%		

DDOR_2024_546050

Project Scope: Bowl 66/4.16kV –

Ohio 4kV - Recable 350CLP to 1000JCN

Example Type: Project is still needed

The subtransmission project examples below include one that is still needed, one that is delayed and one that is no longer needed in the 10-year planning period and therefore no longer included in the DUPR.

Figure 5-11: Subtransmission Examples for Step 13 Process

Subtransmission Project Development

DDOR_2024_TSP STV36800	Year Created	2024											
PY 2024	Deficiency (MW, MVAR or VPU)						Deficiency %						
OD Date	2024 ^A	2025 ^A	2026 ^A	2027 ^A	2028 ^A	Units	2024 ^B	2025 ^B	2026 ^B	2027 ^B	2028 ^B		
6/1/2028	0	0	0	4.8	21.1	MVAR	0.00%	0.00%	0.00%	33.33%	146.53%		
PY 2025	Deficiency (MW, MVAR or VPU)						Deficiency %						
OD Date	2025	2026	2027	2028	2029	Units	2025 ^B	2026 ^B	2027 ^B	2028 ^B	2029 ^B		
6/1/2028	0	0	0	38.4	59.3	MVAR	0.00%	0.00%	0.00%	266.67%	411.81%		

DDOR_2024_TSP STV36800

Project Scope: Valley 'ABCD' 500/115 (S) - Install
57.6 MVAR of capacitors

Example Type:

- Project Still Needed

DDOR_2019_8252	Year Created	2019										
PY 2024	Deficiency (MW, MVAR or VPU)						Deficiency %					
OD Date	2024 ^A	2025 ^A	2026 ^A	2027 ^A	2028 ^A	Units	2024 ^B	2025 ^B	2026 ^B	2027 ^B	2028 ^B	
6/1/2025	0	6.8	9.1	14.6	13.6	MW	0.00%	8.19%	10.96%	17.59%	16.39%	
PY 2025	Deficiency (MW, MVAR or VPU)						Deficiency %					
OD Date	2025	2026	2027	2028	2029	Units	2025 ^B	2026 ^B	2027 ^B	2028 ^B	2029 ^B	
6/1/2026	0	1	3.5	4.8	6.7	MW	0	0.012	0.0422	0.0578	0.0807	

DDOR_2019_8252

Project Scope:

Saugus - Colossus - Lockheed - Pitchgen 66 kV
Subtransmission Line:

Rebuild 1.82 miles of Pitchgen leg

Example Type: Project delayed/deferred

DDOR_2024_8660	Year Created	2024										
PY 2024	Deficiency (MW, MVAR or VPU)						Deficiency %					
OD Date	2024 ^A	2025 ^A	2026 ^A	2027 ^A	2028 ^A	Units	2024 ^B	2025 ^B	2026 ^B	2027 ^B	2028 ^B	
6/1/2026	0	0	3	4	4	MW	0.00%	0.00%	2.40%	3.20%	3.20%	
PY 2025	Deficiency (MW, MVAR or VPU)						Deficiency %					
OD Date	2025	2026	2027	2028	2029	Units	2025 ^B	2026 ^B	2027 ^B	2028 ^B	2029 ^B	

DDOR_2024_8660

Project Scope:

Install New 66kV Subtransmission Line

Example Type:

Cancelled,

not included in PY25 report

DDOR_2022_8469	Year Created	2022												
PY 2024	Deficiency (MW, MVAR or VPU)						Deficiency %							
OD Date	2024 ^A	2025 ^A	2026 ^A	2027 ^A	2028 ^A	Units	2024 ^B	2025 ^B	2026 ^B	2027 ^B	2028 ^B			
6/1/2026	0	0	0	0.26	1.52	MW	0.00%	0.00%	0.00%	2.17%	12.71%			
PY 2025	Deficiency (MW, MVAR or VPU)						Deficiency %							
OD Date	2025	2026	2027	2028	2029	Units	2025 ^B	2026 ^B	2027 ^B	2028 ^B	2029 ^B			
6/1/2025	0.00	0.00	5.02	7.52	7.2	MW	0.00%	0.00%	41.97%	62.88%	62.88%			

DDOR_2022_8469

Project Scope: Valley 115/12 (D) –
New DSP circuit #11 and Substation Capacity

Example Type:

- OD date accelerated
- Capacity added

5.3.2. Estimate Capital Cost for Candidate Deferral Projects - Step 14

This section would normally review the process SCE used to develop the capital cost estimate contained in the DUPR and used to calculate LNBA values for a small sample of planned investments. The V&V review of this step is not included in the IPE for this cycle per the approved IPE Plan for this cycle.

5.4. PROCESSES TO DEVELOP CANDIDATE DEFERRAL LIST AND PRIORITIZE

5.4.1. Development of Candidate Deferral Projects - Steps 15-17

These steps would normally review the development of the list of Candidate Deferral Opportunity (CDOs) Projects from the Planned Investment List through the application of Technical and Timing Screens. However, since the CPUC paused deferral aspects of the DIDF there are no CDOs, and this step was not performed in this cycle and will not be performed in future cycles.

5.4.2. Calculate LNBA Values - Step 18

This section would normally review the development and use of LNBA Values. The review of this step was not included in this cycle's V&V as reflected in the approved IPE Plan.

5.4.3. Compare Forecast and Actuals at Circuit Level for 2023 - Step 19

This step includes a comparison of forecasted and actual loads for 2024 and a review of similar analysis for the previous three years. This type of analysis has been included for the last four cycles. In the 2021 DIDF cycle, the comparison was made for just the Candidate Deferral Circuits with actuals and forecast to be made on the same basis - in that case on a 1 in 10-year basis. Based upon a recommendation in the 2020 DIDF cycle, the comparison made in the 2021 report (again on a 1-in-10 basis) is for a "statistically significant" number of circuits which has been set at 10% of the number of all circuits. The purpose of this analysis is to get some insight into the "accuracy" of the overall circuit planning process recognizing that there are many variables that can affect the comparison that are beyond the control of the utility. In this and the previous cycle SCE developed and made available data that allowed the IPE to perform this analysis on all of SCE's circuits - except those that were involved in a load transfer which makes analysis considerably more complex.

A comparison of the percentage difference in the actual and forecasted load from the 2021-22 2022-23 and 2023-2024 DIDF cycles were included in the 2024 IPE DPAG Report. The percentage differences were calculated for all of these cycles as the actual load less the forecast load divided by the actual load for roughly 300 circuits which were randomly selected for this analysis. The results of this smaller data set indicated that there was a slight bias toward under forecasting. For example, for the 2021-22 cycle the actual load for more than half of the circuits is higher than the forecast load - of the 333 circuits 227 or 68% had positive errors indicating that the forecast was lower than the actual. Reviewing the data for the 2020/2021 cycle, we also see a similar bias to the right, actuals greater than forecast - of the 292 circuits 166 or 56% have actuals greater than forecast.

In the 2022-2023 cycle's data there was once again a slight bias toward under-forecasting - of the 1925 circuits in the data, 1254 or 65% have actual values that are greater than forecast.

The data for last cycle indicated a reversal to previous data in that the data suggested a definite over forecasting bias with 1760 (or 62%) of the overall 2839 samples being negative (over-forecasting) values and 840 (or 30%) samples with positive values (under-forecasting).

The data for all of the circuits in this cycle (2024-2025) is plotted in [Figure 5-16](#). The bars on the right side of the histogram plot (those with positive values) show the number of circuits where the actual load is higher than the forecasted load (under-forecast). Conversely, the bars on the left side of the plot show the number of occurrences where the actual load is

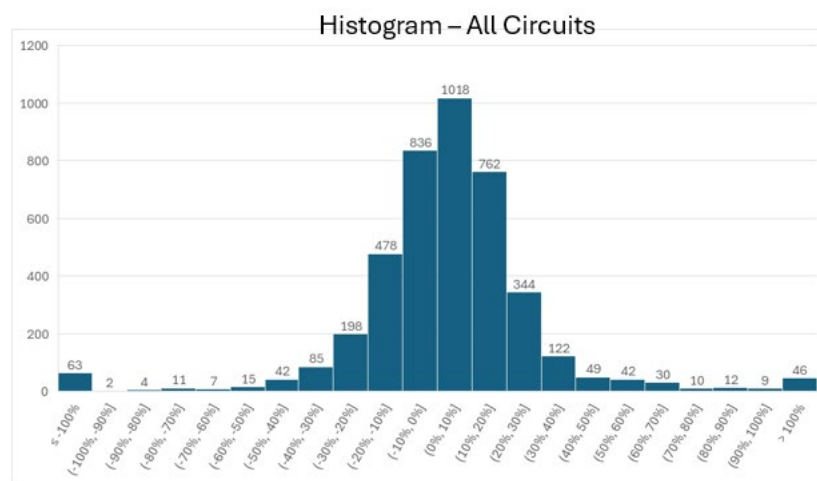
lower than forecast (over-forecast). Note that the plotting software includes values of zero in the first negative bar in the chart. We once again see a normal type of distribution but in this cycle's data we see a slight under forecasting bias with 2446 (or 58%) of the overall 4185 samples being positive (under-forecast) and 1739 (48%) being negative (over forecasting).

To determine what might be causing this shift in bias from over forecasting in the last cycle to under forecasting in this cycle we examined the errors for all circuits without known loads and all circuits with known loads. We performed this analysis to see if circuits whose load forecast included a known load project might be impacting the overall error trend since as we have seen from the known load tracking data discussed earlier that less than 20% of the known load projects that were projected to be completed actually completed in 2024. Thus, for the circuits whose known loads were not completed, it is likely they would have an over forecast error equal to about the size of the known load.

Analyzing the data for circuits without known loads we found a similar and slightly larger bias toward under forecasting - 64% had positive errors (under forecasting) and 36% had negative errors (over-forecasting). For the circuits with known loads, however, we found a slight bias toward over-forecasting with 53% had negative errors (over forecasting) and 47% had positive errors which shows a bias toward under forecasting. It appears that the fact that known loads were not completed as originally predicted has resulted in an over forecasting bias but not enough to result in a bias to over-forecasting when considering all circuits.

We are still examining the data to determine why such an overall shift to under- forecasting has occurred and will report in the Post DPAG Report of any additional findings we may have.

Figure 5-12: All Circuits -Percent Difference between Forecast and Actual



5.5. OTHER IPE WORK

5.5.1. Review Implementing of Planning Standard and/or Planning Process - Step 22

This review was completed in the 2020 DIDF cycle and no follow up work was planned for this cycle.

5.5.2. Review List of Internally Approved Capital Projects - Step 23

This review was completed in the 2020 DIDF cycle. A small number of follow up items were recommended for the 2021 cycle which were completed in March 2022. No work was planned for this Step in this cycle.

5.5.3. Respond to and Incorporate DPAG Comments - Step 24

The IPE was available during the SCE DPAG meeting and the SCE Follow-Up DPAG meeting to respond to questions raised. We worked with SCE on responses that involved material raised during the IPE presentation at the DPAG meeting.

5.5.4. Track Solicitation Results to Inform Next Cycle - Step 25

This review was completed in Q3 of 2022. A solicitation tracking tool (XCEL workbook) was developed by the utilities' Independent Evaluators (IE) at the Direction of the Energy Division. The IPE participated in the definition of the data to be tracked. Going forward the IEs for each utility will update the information in the tracking tool on a regular basis as appropriate and the IPE will have no further role in the future.

5.5.5. Treating confidential material in the IPE Report - Step 26

The IPE work products have followed the process and steps included in this Business Step in developing the IPE Final Report. Additional actions were taken to minimize the material that is redacted in the public version of this report to maximize the readers' ability to understand what the IPE did during this DIDF cycle.

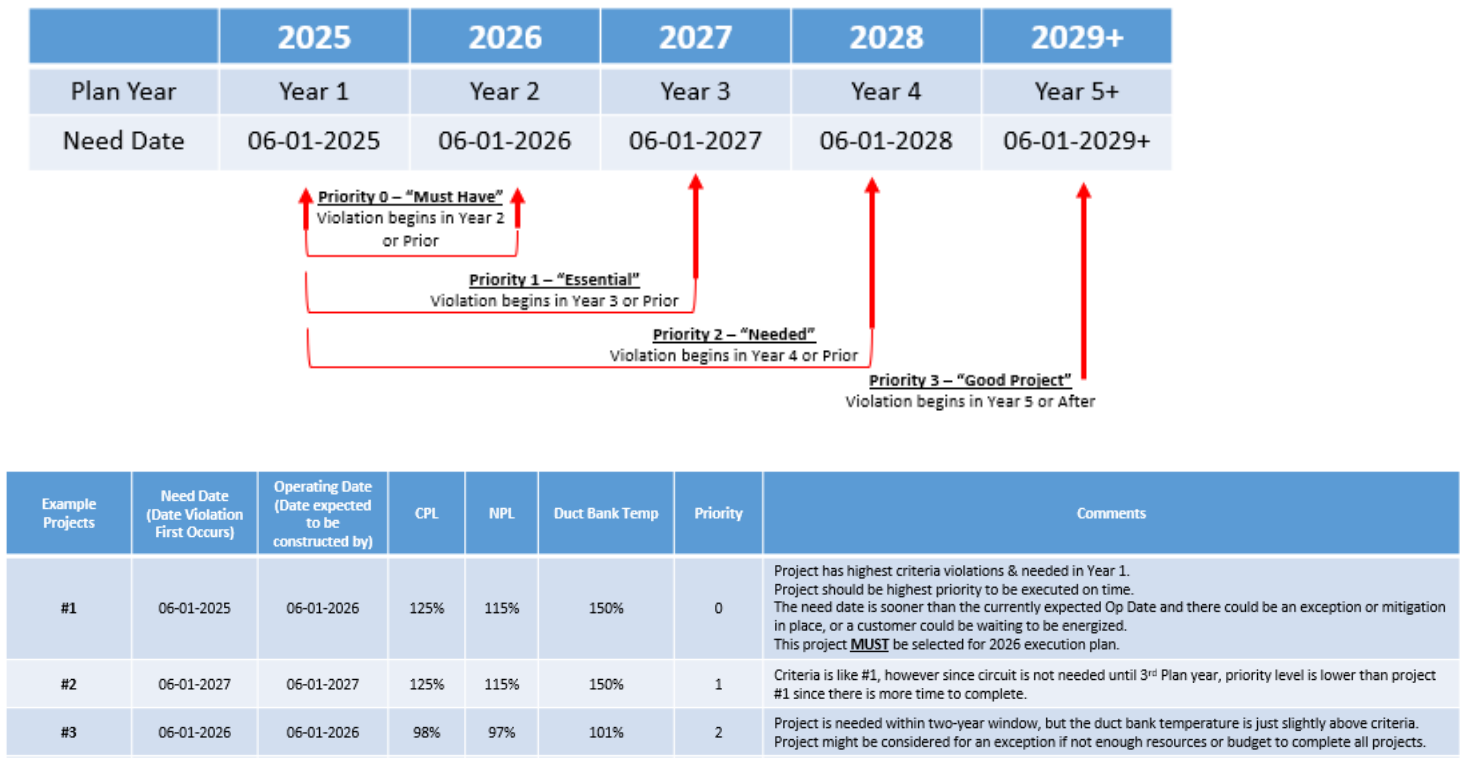
5.5.6. Project Prioritization - Step 27

In this section we review the process that SCE uses to prioritize planned projects for execution. The overall approach/process is summarized below:

- Distribution Engineers assign a priority to projects based on the latest forecast available and with factors such as
 - How immediate are the needs
 - Which projects have the greatest criteria violations
 - When a project can expect to be completed
- Need Date is a function of
 - Date violation first occurs, or date customer needs project constructed by
 - Updated to reflect actual Need Date of project, even if in past
- Operating Date
 - Date project is expected to be constructed, based upon current cycle times
 - Possible that project could be targeted for an earlier completion date, but acceleration could be impacted by other issues not known until design is underway (easements, moratoriums, environmental restrictions, permitting issues, etc.)
- Distribution Engineers are responsible for selecting the Priority Level and providing applicable justification
 - reprioritizing annually, so that as the Year Needed gets closer, the priority will increase
 - Using the latest forecast to review needs for existing projects and establish needs for new projects
- Existing projects can be reprioritized
 - Example: a customer pauses construction, and the Need Date is later in plan, planning & execution teams would discuss path forward depending on the project status (already scheduled, design complete vs design not yet started) (this aspect of the prioritization process is Step 13)
- Project execution organizations will select projects with highest priority for execution first to focus efforts on those projects needed sooner
- If resources/budget is limited, projects will be approved for execution in order of priority which is the method of determining which planned solutions are designated planned investments and others are not.
- For PY25 no projects were selected as Planned Solutions

In Figure 5-13 below (provided by SCE) we see a graphical representation of SCE's prioritization process. In the top table we see four types of priorities - Must Have, Essential, Needed and Good Project, which are based upon when violations begin. The bottom table includes three examples of the process of assigning priorities to projects. The text in the Comments column provides information that is typically considered in the priority setting process.

Figure 5-13: Prioritization of Projects Approach and Examples



5.5.7. Project Execution Tracking Data and Metrics – Step 28

This section will review the Project Execution Tracking Data and Metrics provided by SCE in its 2025 GNA/DUPR.

Ultimately SCE indicated that its data template for project execution data and metrics template will include additional details on all ongoing and prior 3 years (starting with 2026 filing) completed distribution capacity projects included in the Distribution Upgrade Projects Report (DUPR)

SCE noted that in alignment with 3.16 in the Track 1 Decision D.24-10-030, Oct 2024 Ruling, SCE will track the project lifecycle information to provide transparency with respect to the execution of the distribution capacity projects as well as the Distribution Planning Process.

For the 2025 implementation, only new projects submitted after D. 24-10-030 were issued are included for 2025 and an addition was made of an DUPR/DUPR ID to the Known Loads Report. In 2026 and beyond SCE indicated that 3 yrs prior projects information will be included. Also, some additional future enhancements which require standardization of internal processes are contemplated.

Alignment of the execution tracking data with known load data is through the use of the DUPR/DUPR Project ID that has been added to the known load tracking data set. Also, through the separation of items into distribution and substation level components.

SCE's tracking data set is provided in a workbook template that is very similar if not identical to the workbook template previously developed by the Energy Division.

Appendix A IPE Scope

R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

Attachment A Listing of Schedule and IPE-Specific Reforms for the 2020-2021 DIDF Cycle

1. IPE-specific reforms for the 2020-2021 DIDF Cycle are implemented within the IPE Scope of Work presented in Attachment B.
2. IOU contracts with the IPE for the full scope of work identified in Attachment B shall be executed by the IOUs to allow for IPE Plan development to begin as soon as possible, ideally on or before **April 17, 2020**.
3. The IOUs shall work with the IPE and Energy Division to develop IPE Plans specific to each IOU such that the IPE can submit the Draft IPE Plans to Energy Division for review on or before **May 15, 2020**.
4. The IPE scope of work may be modified by Energy Division as needed for the IPE to successfully complete each assignment. The IOUs will promptly submit a Tier 1 Advice Letter to notice changes in scope should a scope change differ significantly from the scope described in Attachment B. Minor changes should not necessitate an Advice Letter filing.
5. As required by Energy Division on an annual basis, Pre-DPAG and Post-DPAG activities may include workshops; new, re-opened, suspended, or modified working groups (e.g., Distribution Forecast Working Group); and IOU presentations and deliverables.
6. During the Post-DPAG period and in consultation with the IPE, Energy Division may identify exemplary GNA/DDOR documentation components, analytical approaches, or data strategies implemented by one or more IOUs and require that each IOU implement the reform in future DIDF cycles.

(end of Attachment A)

- 1 -

R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

Attachment B IPE Scope of Work for DIDF Implementation

Term

- January 1st each year to July 31st the following year with the term subject to update by Energy Division if needed to support each DIDF cycle.

Pre-DPAG Period

- Develop an ***IPE Plan*** for each IOU describing the GNA/DDOR review process and detailed approach to Verification and Validation of all data used by the IOUs to prepare their DIDF filing materials.
 - Verification and Validation will include a thorough investigation of the following IOU processes, among others:
 - Collecting circuit loadings and performing weather adjustments;
 - Determining load and DER annual growth on the system level;
 - Disaggregating load and DER annual growth to the circuit level;
 - Checking sum of all disaggregated load and DERs against system-level values;
 - Adding incremental known loads to circuit level forecasts;
 - Developing load, DER, and net load profiles and determining net peak loads;
 - Adjusting for extreme weather;
 - Comparisons to equipment ratings to determine if ratings will be exceeded;
 - Incorporating load transfers, phase transfers, correcting data errors;
 - Compiling GNA tables showing need amount and timing; and
 - Following the IOU's planning standard and/or planning process.
 - GNA/DDOR report review will include an in-depth analysis of the following IOU steps, among others:
 - Developing recommended solutions (planned investments);
 - Implementing the IOU's planning standards and/or planning process;
 - Estimating capital costs for planned investments;

R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

- Developing list of candidate deferral projects through application of screens (timing and technical);
- Developing operational requirements;
- Prioritization of candidate deferral projects into tiers;
- Calculating LNBA values; and
- Comparing prior-year forecast and actuals at circuit level for candidate deferral projects.
- Work directly with the IOUs and Energy Division to develop draft plans as needed. Development of the draft IPE Plans may include, among other activities:
 - Meeting with the IOUs and Energy Division to identify and understand each business process and tool used to complete their GNA/DDOR filings.
- Facilitate or participate in stakeholder workshops to receive feedback on the IPE Plans.
- Review and incorporate comments in the final IPE Plans.
- Submit final IPE Plans to Energy Division and the IOUs with recommendations for future improvements to the plans.
- Other technical support assignments as defined by Energy Division to ensure the IPE and Energy Division will receive from the IOUs the data and cooperation necessary to complete the required evaluation of the GNA/DDOR filings.

DPAG Period

- Participate in all workshops and meetings during the DPAG period. Prepare and deliver presentations or handouts as requested by Energy Division (*e.g.*, final IPE Plan presentations).
- Develop an *IPE Preliminary Analysis of GNA/DDOR Data Adequacy* for all three IOUs.
- Review any comments on the preliminary analysis that may be received and discuss the results with Energy Division.

R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

- Facilitate meetings with Energy Division and the IOUs to correct data inadequacies and prepare further documentation and provide technical support as needed.
- Fully implement each IPE Plan as defined in the final IPE Plans.
- Develop an ***IPE DPAG Report*** for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes.
- Submit the draft reports to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included or to clarify specific details.
- Circulate the final IPE DPAG Reports to stakeholders (public and confidential versions).
- Other technical support assignments as defined by Energy Division to ensure the DPAG process is successfully completed.

Sample Size

- The scope of review conducted by the IPE for each IOU process may encompass the full set of circuits/projects or a subset/sample of circuits or projects. Where sampling is determined to be appropriate by the IPE in consultation with Energy Division, the size of the sample set for each case will be determined by the IPE based on the application of engineering judgement.

Post-DPAG Period

- Develop a single ***IPE Post-DPAG Report*** covering all three IOUs; comparing their current and prior filings; evaluating DIDF DER procurement, operational, cost, and contingency planning outcomes; reviewing IOU compliance; and making recommendations for process improvements and DIDF reform.
- Coordinate with and support the Independent Evaluator (IE) with IE activities and the development of IE reports as needed.
- Submit the draft report to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included.

Proposed IPE Scope of Work (Draft)

Proposed Changes to Current Scope of Work

Current IPE Scope	Recommendations
Step 1 - Collect 2024 Actual Circuit Loading and adjust/normalize for weather as needed	Keep in future cycles
Step 2 - Determine Load and DER Annual Growth on System Level	Keep in future cycles
Step 3 - Disaggregate Load and DER Annual Growth to the Circuit Level	Keep in future cycles
Step 3a - Check sum of all disaggregated load and DERs same as CEC IEPR System level values	Keep in future cycles
Step 4 - Add Incremental Load Growth Projects to Circuit Level Forecasts (those loads not in CEC forecast)	Keep in future cycles
Step 5 - Convert DER growth load to 8760 or 576 profile as needed	Recommend skipping unless process changed.
Step 5 - Convert peak of load to 8760 or 576 profile as needed	Recommend skipping unless process changed.
Step 5 - Convert base forecast and weather normalization adjustment to 8760 or 576 profile as needed	Recommend skipping unless process changed.
Step 6 - Derive net load profile	Recommend skipping unless process changed.
Step 7 - Determine net peak load	Recommend skipping unless process changed.
Step 8 - Adjust for extreme weather	Keep in future cycles
Step 9 - Initial comparison to equipment ratings to determine if ratings exceeded	Recommend skipping unless process changed.
Step 10 - Evaluate no cost solutions - incorporate load transfers, phase balancing, correct data errors	Recommend skipping unless process changed.
Step 11 - Comparison to equipment ratings to determine if ratings exceeded	Recommend skipping unless process changed.
Step 12 - Compile GNA tables showing need amount and need timing, etc (consistent with IOU's documented planning standards and/or planning process)	Keep in future cycles
Step 13 - Develop Recommended solution and generate list of Planned Investments (follow the IOU's documented planning standards and/or planning process)	Keep in future cycles

Step 14 - Estimate capital cost for candidate deferral projects	Eliminate
Step 15 - Development of Candidate Deferral Projects list through application of screens (timing and technical)	Eliminate
Step 16 - Development of operational requirements for CDO (daily, monthly, annually, etc)	Eliminate
Step 17 - Prioritization of Candidate Deferral Projects into Tiers	Eliminate
Step 18 - Calculation of LNBA ranges and values for all planned projects.	Eliminate
Step 19 - Compare 2023 Forecast and Actuals at Circuit Level [proposed change would increase from ~10% of circuits to include all circuits if possible]	Keep in future cycles
Step 20 - Analyze known load tracking dataset and verify the calculation of known load metrics	Keep in future cycles
Step 22 - Review implementing of planning standard and/or planning process	Eliminate
Step 23 - Review list of internally approved capital projects	Eliminate
Step 24 - Respond to and incorporate DPAG comments	Keep in future cycles
Step 25 - Track solicitation results to inform next cycle	Eliminate
Step 26 - Treating confidential material in the IPE report	Keep in future cycles

Proposed Additions to IPE Scope of Work

Decision	New items	IPE Scope
3.1-Allow Utilities to Use Bottom-Up, Known Load Data to Determine Growth	Definition of Reliable Bottom-up Data (as well as, Customer energization Request, Known Load, Pending Load etc.) (Page 42) Note: Decision 3.1 allows Utilities 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. Further, this decision directs that, in years without reliable bottom-up data, total growth should correspond to the forecast amount and not be adjusted downwards.	Annual verification and validation for the use of known loads already being performed as a part of Step 2 of the current V&V process. No new steps required.
3.2 – Require Utilities to Improve Method for Setting Caps on Load Growth from IEPR data.	IOU to work with CEC and CPUC to staff in developing proposals for the method and accounting for discrepancies between the system and circuit level. (Page 43) Decision 3.2 further focuses on developing proposals for the method and accounting for discrepancies between the system and circuit level (forecasts). The forecast at the system level (IEPR) is a coincident peak load forecast and is not necessarily equal to the sum of the peak loads on all the circuits. So, a methodology needs to be devised to develop circuit level forecasts that takes this into account. This decision approves, with one modification, the recommendation to require Utilities to submit Advice Letters proposing how they will improve their methods for setting caps on load growth based on the IEPR forecasts and other data. Utilities shall file Tier 3 Advice Letters. (Page 47)	Verify and validate IOUs' use of methodology for accounting for discrepancies between the system and circuit level load forecasts in the DPP. Annual starting 2025-2026 cycle. Annual verification and validation of methods for setting caps on load growth from IEPR data already covered under Step 2 of the current V&V process. No new steps required.
3.4 – Require Utilities to Expand the DPP Forecast Horizon to Align with IEPR and Expand the Planning Horizon to 10 Years.	To ensure transparency, utilities shall provide a description of the thermal capacity evaluation methodology in the annual GNA report (Page 55)	No new steps required to verify the expanded DPP planning horizon. The current V&V will be extended from 5 years to 10 years. Annual starting 2025-2026 cycle.

3.5 – Require Utilities to Use Scenario Planning to Improve Forecasting and Disaggregation	Workshops to develop scenario planning methodology and process. (Page 59) Utilities shall develop scenario planning capabilities that enable them to: (1) analyze multiple forecasts; (2) identify capacity deficiencies for each scenario and report them in the annual GNA; and (3) develop one investment plan informed by the multiple scenarios and reported in the DDOR or successor filing. (Page 61)	Attend workshop. One Time. Estimated Q1 2025 Verify and validate each DPP scenario and how utilities create one investment plan informed by multiple scenarios in the annual DPEP. Annual starting 2025-2026 cycle. • Develop draft IPE Plan for V&V of scenario planning – Q2 2026 • Finalize IPE plan – Q3 2026 • Perform V&V Q3 2026
3.6 - Require Utilities to Improve Disaggregation Methodology for Load Growth	Require Utilities to Improve Disaggregation Methodology for Load Growth (Page 62) This decision adopts the recommendation to require Utilities to improve disaggregation methodologies for load growth and distributed energy resources but delays implementation to the 2027 GNA and the 2026-2027 DPP cycle. To track progress toward improved disaggregation in the interim, Utilities shall report annually in the GNA on the development of advanced disaggregation methodologies and present these at the annual Distribution Forecast Working Group workshops or successor workshops. (Page 65)	Verify and validate the improved disaggregation methodology. Annual starting 2026-2027 cycle. Q3 2027. • Develop draft IPE Plan for V&V of improved disaggregation methodology – Q2 2027 • Finalize IPE plan – Q3 2027 • Perform V&V Q4 2027
3.7 - Require Utilities to Create Pending Loads Category in the DPP	Utilities are directed to provide pending load data and include the source of the data in the annual known load tracking filing, as part of the GNA/DDOR or successor report and orally reported during the DPAG or successor workshop (Page 76)	Attend workshop. One Time. Estimated Q1/Q2 2025 Verify and validate pending load data and source in annual reports and DPAG or successor workshop. Annual starting 2025-2026. • Develop draft IPE Plan for V&V of Pending Loads – Q2 2026 • Finalize IPE plan – Q3 2026 • Perform V&V Q3 2026

3.8 – Require Utilities to Develop Prioritization Methods Beyond the Current Consideration of Project Need Dates	Utilities to report how projects identified throughout the distribution planning horizon have been prioritized for execution. This decision also requires inclusion of this information in the annual GNA/DDOR or a successor report instead of the previously required Advice Letter (83)	Verify and validate the process used by utilities to prioritize projects for execution. Annual starting 2024-2025 cycle. • Develop draft IPE Plan for V&V of prioritization methodology – Q2 2025 • Finalize IPE plan – Q3 2025 • Perform V&V Q3 2025
3.9 – Require Utilities to Consider Distribution Planning Results in Other Distribution Work	Utilities to consider distribution planning results in other distribution work aka Integrated planning (Page 83) A workshop shall be held by Utilities during the third quarter of 2025 to present Utility proposals for integrated planning and solicit feedback from stakeholders on issues presented, including cost containment considerations. A second workshop shall be held by Utilities no more than eight weeks following the first workshop to present updated proposals based on feedback from the first workshop. (Page 86)	Attend workshop. One Time. Estimated Q3/Q4 2025. Verify and validate that integrated planning projects meet the established requirements. Annual starting 2026-2027. • Develop draft IPE Plan for V&V of integrated distribution planning – Q2 2027 • Finalize IPE plan – Q3 2027 • Perform V&V Q3 2027
3.11 – Require Utilities to Prepare a Load Flexibility DPP Assessment	Require Utilities to Prepare a Load Flexibility DPP Assessment. (Page 98)	Review EIS Part 2 studies and attend workshop. One Time. Estimated Q1 2026.
3.15 – Require Utilities to Include Metrics to Evaluate Equity in Utility Distribution Plan Reporting	Require Utilities to Include Metrics to Evaluate Equity in Utility Distribution Plan Reporting (Page 119) The Commission clarifies that while these metrics are requested for evaluation purposes, there is no framework wherein equity metrics are used for forecasting or planning distribution. The intention of this proposal is an annual evaluation of equity in distribution planning and does not involve modifying the planning process based on equity considerations. (Page 123)	Support the ED and the IOUs in finalizing and standardizing the tracking and reporting of the Equity Metrics. One Time. Estimated Q2 2025. Verify and validate equity metrics calculated by the utilities and reported by the utilities annually. Annual starting 2025-2026 DPP cycle. • Develop draft IPE Plan for V&V of equity metrics – Q2 2026 • Finalize IPE plan – Q3 2026 • Perform V&V Q3 2026

3.16 – Require Utilities to Include Metrics to Track Project Execution in Utility Distribution Plan Reporting	Require Utilities to Include Metrics to Track Project Execution in Utility Distribution Plan Reporting (Page 123) *also see Table 12 and Table 13. Table 12 * Additional Details for All Ongoing and Prior Three Years Completed Distribution Capacity Projects Table 13* Additional Project Execution Tracking Data	Support the ED and the IOUs in finalizing and standardizing the tracking and reporting required to track project execution based on Table 12, 13, and the requirements of R24-01-018 (Appendix B - Decision Establishing Target Energization Time Periods And Procedure For Customers To Report Energization Delays). One Time. Estimated Q2 2025 Verify and validate the project execution data and metrics submitted by the utilities. Annual starting 2024-2025 DPP cycle. • Develop draft IPE Plan for V&V of project execution metrics – Q2 2025 • Finalize IPE plan – Q3 2025 • Perform V&V Q3 2025
3.18 - Require Utilities to Facilitate Better Coordination and Data Sharing Between the DPP and Transportation Electrification Planning	Require Utilities to Facilitate Better Coordination and Data Sharing Between the DPP and Transportation Electrification Planning (Page 135)	Verify and validate how TEPP outputs are used in DPP. Annual starting 2025-2026 earliest. • Develop draft IPE Plan for V&V of TEPP coordination – Q2 2026 • Finalize IPE plan – Q2 2026 • Perform V&V Q3 2026

Appendix B Copy of the IPE Plan

Note: The 2024/2025 IPE Plan for SCE is included following this page. This version of the Plan is updated to reflect the final dates for all the steps.



Final IPE Plan for 2025-26 DIDF Cycle - Southern California Edison

Submitted to California Public Utility Commission

August 15, 2025

Submitted by:
Resource Innovations
Sundar Venkataraman
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Contents

1	Introduction and Background	1
2	Description of the Plan	2
2.1	Definitions Used in the Plan and Other Deliverables	2
3	IPE Plan.....	3
3.1	Revisions to the IPE Plan for this Cycle	4
Appendix A	CPUC 4/13/20 Ruling Excerpts.....	A-1
Appendix B	Updated Scope of Work Dated March 4, 2025	B-6

1 Introduction and Background

The Independent Professional Engineer (IPE) services for the 2025-26 Distribution Investment and Deferral Framework (DIDF) Process is per CPUC decision (D.18-02-004), Administrative Law Judge's Ruling (R. 14-08-013) issued May 7, 2019, and Administrative Law Judge's Ruling Modifying DIDF (R.14-08-013) issued April 13, 2020 which defined the original IPE scope of work (Appendix A). This original scope of work has been modified by subsequent orders and rulings, as well as updates to the scope of work made by the Energy Division on March 4, 2025 which modifies the original scope and includes additional scope items to support the High DER proceeding. This updated scope of work is included as Appendix B.

The schedule for the IPE Verification and Validation (V&V) process in this cycle will follow the Administrative Law Judges' ruling setting schedule for the 2025-2026 Distribution Investment Deferral Framework cycle issued on March 6, 2025 and is shown below:

- Draft IPE Plan due week of May 19, 2025.
- Final IPE Plan due August 15, 2025.
- IPE Preliminary Analysis of GNA/DUPR Data Adequacy for all three IOUs due September 5, 2025.
- IPE Distribution Planning Advisory Group (DPAG) report for each IOU presenting GNA/DUPR review findings and Verification & Validation outcomes due November 6, 2025.
- IPE Post DPAG Report covering all three IOUs, comparing their filings, reviewing compliance, and making recommendations for process improvements due March 16, 2026.

The draft IPE Plan for 2025/2026 DIDF cycle was distributed to stakeholders on May 23, 2025 to facilitate stakeholder comments prior to finalizing the IPE Plan.

2 Description of the Plan

2.1 Definitions Used in the Plan and Other Deliverables

To facilitate understanding of the IPE scope of work, the following definitions are included and will be used in the Plan and throughout all of the IPE work products and deliverables.

Verification – Is a review performed by the IPE during which an independent check is performed to determine if the results produced were developed using data assumptions and business processes that were defined and described by the utility or are based upon standard industry approaches that do not have to be defined and described. In other words, “Did the IOU follow their own processes correctly as defined and described by the IOU?”

Validation – Is a review performed by the IPE during which an independent assessment is performed of the appropriateness of the approach taken by the utility to perform a task from an engineering, economics, and business perspective. In other words, “Are the processes implemented by the IOU the best way to identify all necessary planned solutions and investments. And to what extent were the IOU methodologies appropriate and effective?”

The IPE Plan covers the business processes that the IOUs use to identify which distribution or sub-transmission projects are recommended to proceed to implementation. One of the core purposes of the plan is to answer the question - Are the IOUs identifying every project that will be needed to provide the new or additional service requirements of their customers early enough to provide the service in a timely manner?

The business processes in the Plan are organized generally in the order that they are performed. Starting with capturing the peak load values for each circuit, using the CEC IEPR forecasts to develop utility specific system level values which are then disaggregated to the circuit level, adjusted for known and pending loads and then used to determine if there is an overload or other issue during the planning period. For circuits that have a need, the best planned investment is selected.

3 IPE Plan

The heart of the IPE Plan is the material contained in Table 3-1. This table lists the business processes, roles of the utility and IPE, target timing and information requirements for each business process in the IPE scope. Listed below is a more detailed description of the contents:

- IOU Business Process / IPE Review Step – This column includes a number for each business process included in the table. To make it easier for readers who will be looking at more than one utility IPE Plan, the process was started with the same numbering for all three utilities and that set of numbers was maintained as much as possible. In cases where additional steps needed to be added to accommodate a utilities specific unique process a letter was added to the previous number. For example, the step after Step 3 was added and was number Step 3a. For cases where steps are not needed, they will be spelled out in the table.
- Business Process / IPE Review Step Description – This column contains a general description of the business process being reviewed.
- Plan for 2025/26 DIDF Cycle – This column includes several types of information:
 - A brief description of what the review will include and whether it would include a review of a subset of the total number of elements (i.e., circuits) or all elements and what is being examined.
 - Roles which include the role of the utility overall and the role of the IPE for both the verification and validation review. For one or both reviews, an indication is provided in most cases, for what the IPE will be checking for or confirming in the review.
Note that there are generally two approaches to performing a verification. The first is a demonstration wherein the utility develops the necessary spreadsheet or other mechanism to show how the business process developed the results of interest and the IPE performs a walk through to view the demonstration by the utility. The second approach is wherein the IPE develops a spreadsheet or other mechanism to calculate the results of interest using data provided by the utility and then compares the results to the utilities' numerical results.
- Target Timing – This column includes a target timing for the reviews in the business process in this row or in the timing that data will be provided to the IPE.
- Data/Information Requirements – This column includes the data or information that the IPE needs to perform its review and in some cases the date the information is required.

3.1 Revisions to the IPE Plan for this Cycle

As per the updated IPE Scope of Work, the following verification and validation steps will be skipped in this cycle since SCE confirmed that the business process they used in these steps are the same as those used in the prior cycle.

- Steps 5-7 - Convert Peak Growth to 8760 Profile, Determine Net Load and Peak Load
- Steps 9-11 - Initial Comparison to Equipment Ratings, Evaluate No Cost Solutions and Comparison to Equipment Ratings after No Cost Solutions
- Step 14 - Development of capital costs for the planned investments.

These steps are not being removed permanently from the IPE V&V scope. In addition, as indicated earlier, these steps are only skipped in this cycle since the utility states that the business process for these steps have not changed from the prior cycle. These steps have been included in the table below and will be followed only if the process used by the utility for this cycle is different than used in the previous cycle.

The Energy Division has requested that Step 13 (Development of Planned Investments using Planned Standards) be retained in this cycle to verify and validate the process used by the utilities to determine whether a planned project identified in a previous cycle is still needed based on the results of the current cycle. We will finalize the data and information that needs to be gathered in this step once we have had a discussion with the utilities about their process.

In addition, the verification and validation of the following steps related to the identification and prioritization of Candidate Deferral Opportunities (CDOs) will be skipped in this cycle.

- Step 15 - Development of Candidate Deferral Projects
- Step 17 - Prioritization of Candidate Deferral Projects into Tiers
- Step 16 - Development of operational requirements for CDOs
- Step 18 - Calculation of LNBAs for planned projects

In addition, based on inputs from the ED, the following steps will be skipped in this cycle.

- Step 21 - Review plan for changes to the planning process for the next cycle
- Step 22 - Review implementing of planning standard and/or planning process.
- Step 23 - Review list of internally approved capital projects.
- Step 25 - Track solicitation results to inform next cycle.

Two new steps have been added specifically for this cycle referred to as Steps 27 and 28. An outline of the V&V plan for these steps have been included in this draft plan. The IPE will finalize the data and information that it needs to be gathered for these steps once we have a discussion with the utilities about their process related to these steps.

- Step 27 – Review Methodology used for Prioritization of Planned Projects
- Step 28 - Review Project Execution Tracking Data and Metrics

The IPE V&V steps for 2025/26 DIDF Cycle are shown in Table 3-1 starting on the following page.

Note that target dates are preliminary and based upon the corresponding dates for the previous cycle.

Table 3-1: SCE IPE Review for 2025/2026 DIDF Cycle

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
PROCESSES TO DEVELOP STARTING POINT LOAD, SYSTEM LEVEL VALUES AND DISAGGREGATE TO CIRCUIT LEVEL				
1	Collect 2024 actual circuit loading and adjust for weather as needed	Perform Verification for a subset of circuits selected by the IPE in consultation with the IOU; check results including weather normalization to typical weather day and extreme weather day. Examine weather adjustment factors/relationships for all SCE regions. The review in this Step will include the process described in Step 8 below. Roles: SCE to develop demonstration of weather adjusted readings for 20 circuits (SCADA data) throughout the SCE territory including an overview of the process used. Demonstration to include review of data measurements (SCADA Data) and process to adjust to standard conditions required by following steps of the load forecasting process with a focus on the peak day.	7/1/25	▪ Description of business process used to collect and adjust measurement data ▪ General methodology of weather adjustment factors ▪ Demonstration of measurements/adjustments for 20 selected circuits and underlying data for the selected circuits.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		SCE to demonstrate general methodology of weather adjustment factors for the selected circuits within its service territory. This also includes adjustments due to extreme weather (e.g., 1-in-10). Verification: IPE to review demonstrations and compare the process and results to the process described/presented by SCE. IPE to verify that individual circuit results are those used in the following steps in the load forecasting process (Step 4). Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
2	Determine load and DER annual growth on system level	Perform Verification and Validation on all aspects of this process. Roles:	6/14/25	Provide description of CEC IEPR system forecast(s) used (i.e., low, medium, or high) and link to CEC table(s) used, as available.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		SCE to demonstrate how it used the CEC IEPR system level (annual energy) load and DER forecasts as the basis for its load and DER disaggregation process. SCE to demonstrate how the data for known loads for commercial chargers is used in conjunction with the CEC IEPR data for EVs without double counting these loads. SCE to demonstrate how pending loads are used in the forecasting process at the system level. SCE to provide spreadsheet(s) that demonstrates this process. Verification: IPE to review data provided (spreadsheet) and compare to process summary presented by SCE. IPE to compare output results of this process are the same as those used in the next step of the process (Step 3). IPE to verify that SCE used the load forecast scenario that was approved by the CPUC for use in the DIDF.		▪ Provide description of the process if different than used in 2023 and described in 2023 GNA/DDOR ▪ Provide available spreadsheet used to implement process with breakouts for all known and pending loads used in the process . ▪ Summary data of local known loads that are assumed to be embedded in the CEC IEPR. This data to include type of load, magnitude, timing, and circuit. ▪ Data for vendor forecast data, TEGR data and pending load data used in the DPP and description of how they are used.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
3	Disaggregate load and DER annual growth to the circuit level	Perform Verification for a subset (approximately 10) of circuits selected by the IPE in consultation with SCE. Roles: SCE to demonstrate how it used the results of the previous step (utilization of the approved CEC IEPR system level (annual energy) load and DER forecasts) in the process of allocating system level annual energy values of load and DERs to the circuit level along with known and pending loads. Verification: IPE to review demonstration and compare results to process summary presented by SCE.	6/14/25 Note – the cross check portion of this step (compare results for selected circuits against results used in the following steps) have a Target Date after the GNA report is filed.	Demonstrations and associated spreadsheet.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to compare results for select individual circuits against results used in following steps in the process (starting in Step 4) Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
3a	Check sum of all disaggregated load and DERs same as CEC IEPR System Level values	Perform Verification on this aggregation for all circuit values as well as cross check values used in other Verification checks. Roles: SCE to demonstrate that the sum of all circuit level energy values for load and DERs equals the approved CEC IEPR system level values verified in Step 2 and known and pending loads as appropriate Verification: IPE to verify that the sums of all circuit load and DER values equals to (within a small deviation) the CEC IEPR system values	6/14/25	Demonstrations

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		verified in Step 2 and known and pending loads as appropriate. IPE to verify that selected circuit values used in the summation check match the circuit values used in subsequent steps of the load forecasting process (starting in Step 4). This check will also include a check of known and pending loads at the system level against the sum of the known and pending loads at the circuit level. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
4	Add Incremental load growth projects to circuit level forecasts (those loads assumed not in CEC forecast)	Perform Verification for a subset (approximately 10) of circuits randomly selected by the IPE in consultation with the IOU. Roles: SCE to demonstrate how it adds incremental known loads for cases where the load is in	7/1/25	- Summary of local known loads and values for loads that are not included in CEC forecasts. - Description of discussions with CEC regarding local know loads that are not included in CEC forecasts

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		addition to the CEC system level load forecast. SCE to demonstrate how loads are added and any adjustments to system level values are accomplished. Note: Load that is embedded within CEC IEPR growth is already captured within Business Process Steps 2, 3, and 3a. Verification: IPE to verify that business process demonstration by SCE is the same as described in SCE documentation. IPE to verify that the results for selected circuits are used in subsequent business process steps (Starting with Step 5) Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
5	Convert peak growth to 8760 profile as needed	Perform Verification and Validation for a subset (approximately 10) of circuits selected by the IPE in consultation with the IOU.	7/10/25	Description of process used for load and DERs in tabular view.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
	(skipped in this cycle)	Roles: SCE to demonstrate how it converts load and DER results of previous steps into 8760 values. Verification: IPE to verify that process reflected in the demonstration is the same as described by SCE. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
6	Derive net load profile (skipped in this cycle)	Perform Verification for a subset (approximately 10) of circuits selected by the IPE in consultation with the IOU. Roles: SCE to demonstrate how it combines load and DER on an 8760 basis to obtain a net load profile. Verification:	7/10/25	Description of process used to combine load and DERs in tabular view.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to verify that process reflected in the demonstration is the same as described by SCE. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
7	Determine net peak load (skipped in this cycle)	Perform Verification for a subset (approximately 10) of circuits selected by the IPE in consultation with the IOU. Roles: SCE to demonstrate the process of how it applies shapes to determine peak impact of different growth types (e.g., disaggregated growth before shapes vs. after shapes) similar to the 2021/2022 V/V approach. SCE to review shapes that it uses in this process for all net load components.. Verification:	7/10/25	Description of process used to determine peak impact using shapes.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to verify that process reflected in the demonstration is the same as described by SCE. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
8	Adjust for "extreme weather"	This verification and validation are included in Step 1.	7/1/25	

PROCESSES TO DETERMINE CIRCUIT NEEDS AND DEVELOP GNA

9	Initial comparison to equip. ratings to determine if ratings exceeded (skipped in this cycle)	Perform Verification for a subset of circuits selected by the IPE in consultation with the IOU. Note: The verification and validation of this business process is included in Step 11.	9/26/25	
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IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
10	Evaluate no cost solutions - incorporate load transfers, phase balancing, correct data errors (skipped in this cycle)	Perform Validation and Verification for a subset (approximately 6) examples pulled from separate circuits selected by the IPE in consultation with the IOU. Roles: SCE to demonstrate how it makes adjustments to forecast based upon load transfers, phase balancing, and/or data error corrections. Demonstration will include what data is relied upon to predict the impact of making the proposed changes (i.e., load transfer). Verification: IPE to verify the process reflected in the SCE demonstration is consistent with the SCE description and the result are the same as used in subsequent steps in process of developing the GNA. Validation:	9/26/25	Description of general process used to evaluate no cost solutions.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
11	Comparison to equip. ratings to determine if ratings exceeded (skipped in this cycle)	Perform Verification for a subset (approximately 10) of circuits selected by the IPE in consultation with the IOU. Note the business processes described in Step 9 is covered in this step. Roles: SCE to demonstrate how it determines if there is a “need” and how it determines the need amount. This will include comparison of extreme weather load forecast against appropriate ratings for distribution circuits (overhead and underground). For subtransmission circuits SCE will demonstrate how it uses contingency analysis to determine if there is a need and to determine a need amount. The demonstration will include comparisons where no cost load transfers and phase balancing is included for some of the selected circuits.	9/26/25	Description of process used to determine need/deficiency amount. Description of ratings and their basis used in this step.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		Verification: IPE to verify the process reflected in the SCE demonstration is consistent with the SCE description and the result are the same as used in subsequent steps in process of developing the GNA. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
12	Compile GNA tables showing need amount and need timing, etc. (consistent with IOU's documented planning standards and/or planning process) (skipped in this cycle)	Perform Verification on development of GNA table entries for select circuits also confirming that planning standard/process was followed as appropriate. Roles: SCE to provide confidential version of Planned Investment tables in Excel format that can be filtered by the IPE.	8/15/25 (Public Information) 8/30/25 (Confidential Information) 9/26/25	- Confidential GNA tables in Excel format provided by mid-August. - Copy of planning standard if different than one used in 2021. - Description of process using excerpts from planning assumptions, GNA, and DDOR similar to approach in 2022/23 DIDF cycle. - This step focuses upon an analysis concerning

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		SCE to provide list of planning standards/criteria that were used in the development of the GNA tables. Verification: IPE to verify GNA tables are consistent with previous steps verified and planning standard as appropriate. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		whether planning standards that lead to the identification of needs were followed. It does not include review of the planning standards, themselves.

PROCESSES TO DEVELOP PLANNED INVESTMENTS AND COSTS

13	Develop recommended solution and generate list of Planned Investments (follow the IOU's documented	Perform V&V for a subset of projects selected by the IPE in conjunction with SCE confirming that planning standard/process were followed. This step will include two processes – 1) the process that SCE used to confirm that planning solutions or investments identified in prior cycles are still needed and are the appropriate solution based upon planning	9/26/25 (to be finalized)	Description of process used to develop proposed planned project to address identified need for distribution and subtransmission projects and description of the process used to confirm that projects identified in a previous cycle are still
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IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
	planning standards and/or planning process) (see IPE recommendation in Section 3)	assumptions for load and DER growth and other planning assumptions used in the current DPP cycle; 2) the process to identify the current set of solutions and planned projects identified in the DPP for this cycle. The number of and the specific projects selected for review for these two business processes may not be the same [This V&V process for this step will be updated based on the inputs from SCE] Perform Verification for a subset (approximately 10) of projects selected by the IPE in consultation with the IOU confirming that planning standard/process was followed for both business processes. Roles: SCE to demonstrate/describe process used to determine recommended planned solution for a subset of projects including subtransmission and distribution projects and how it determined which projects identified in		needed and appropriate solutions. A demo of the process and supporting data for ten randomly selected projects with a mix of projects including some driven by a known load, others driven by pending loads and others driven by neither.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		previous cycles are still needed and appropriate solutions to meet the need. Verification: IPE to verify that the SCE demonstration reflects the description of the two process described and provided by SCE. IPE to verify that results shown in the demonstration follow the described process are same as included in DDOR. Validation: IPE to review the two business process for reasonableness and consistency with objectives of the DIDF.		
14	Estimate capital cost for Candidate Deferral Projects (skipped in this cycle)	Perform Validation and Verification for a subset (approximately 6) of Candidate Deferral projects selected by the IPE in consultation with the IOU. Roles: SCE to provide information describing the processes used to develop the capital cost estimates included in the DDOR.		- Information describing the processes used to develop costs and how it relates to the SCE GRC. - Expected Accuracy associated with the process described. - Support cost data for subset of projects in DDOR

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		SCE to describe the Expected Accuracy Level (as defined by AACE or by another method that describes the expected accuracy range in terms of % lower and higher than the estimate) of the capital costs for the Candidate Deferral Projects included in the DDOR. If the Expected Accuracy is different for different projects, SCE to provide the accuracy range for each project.¹ SCE to provide supporting cost information for a subset of projects. Projects to include small, medium, and large projects and new projects and those that have been included in previous DDOR reports. Verification: IPE to verify that the supporting information for the selected projects confirms the process that was used and that the cost data supplied supports the final cost estimate provided by SCE and included in the DDOR.		

¹ During the course of implementing the IPE Plan, the ED in coordination with the IPE will seek to understand the effort and cost associated with improving the accuracy of capital cost estimates (i.e., from a Class 4 estimate accuracy to a Class 3 estimate accuracy).

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		

PROCESSES TO DEVELOP CANDIDATE DEFERRAL LIST AND PRIORITIZE

15	Development of Candidate Deferral Projects list through application of screens (timing and technical) (skipped, no longer required)	Perform Verification for all projects put through screens. Roles: SCE to provide confidential version of Planned Investment table in Excel format that can be filtered by the IPE. SCE to describe the process it used to develop its Candidate Deferral Projects. Verification: IPE to use the Excel tables to develop a list of Candidate Deferral Projects following the process described by SCE. IPE to verify its result (list of Candidate Deferral Projects) match the SCE results included in the DDOR.		- Confidential version of Planned Investment table in Excel format that can be filtered by the IPE. - Description of process used to develop Candidate Deferral Projects - Utilize DPAG materials.
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IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
16	Development of operational requirements (daily, monthly annually etc.) (skipped, no longer required)	Perform Verification for a subset (approximately 4) of Candidate Deferral projects selected by the IPE in consultation with the IOU. Roles: SCE to demonstrate how it developed the operational requirements for a subset of candidate deferral projects including several Tier 1 projects. Verification: IPE to observe results demonstrated by SCE and check to see that they are consistent with the net load shapes and forecasts for the selected projects and that they match the results in the DDOR. Validation:		Describe general methodology similar to 2021 approach. Provide demonstration similar to 2022/23 DIDF cycle.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
17	Prioritization of candidate deferral projects into Tiers (skipped, no longer required)	Perform Verification on prioritization process for all candidate deferral projects including process to develop list of projects that SCE recommends proceed to RFO or PP procurement. Roles: SCE to provide active version (not just values) of the Excel spreadsheet that calculates the metrics and their components used to rank the Candidate Deferral Projects overall and into tiers. Note, in the 2021/2022 DIDF cycle the IOUs have agreed to use a single standard methodology to prioritize/rank Candidate Deferral Projects and to place them in various tiers based upon the prioritization results. SCE to provide active version of spreadsheet (if one is used) used to rank and select candidate deferral projects for procurement.		▪ Demonstrate active spreadsheet that calculates prioritization metrics, components and ranks projects on those results. To include spreadsheets for prioritization of CDOs and for ranking/selecting PP projects. ▪ Description of the IOU standardized prioritization metrics, components and tier ranking methodology and process and PP ranking selection process – all provided by end of-August.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		Verification: IPE to verify that spreadsheet calculations are consistent with the description of the standard IOU prioritization/ranking and tier placement methodology and PP ranking/selection process. IPE to verify that Excel results match the recommended Candidate Deferral Projects overall rankings and placement into tiers and recommended for RFO, SCO or PP procurement included in the DDOR and presented at the DPAG meetings. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		
18	Calculate LNBA ranges and values for all planned investments	Perform Verification for a subset of candidate deferral projects (approximately 6) selected by the IPE in consultation with the IOU. Roles:		▪ Description of the process used to develop LNBA ranges and metric values. ▪ Demonstrate active spreadsheet that calculates

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
	(skipped, no longer required)	SCE to provide an active spreadsheet (not just values) that calculates all LNBA range values that are included in the DDOR for all Candidate Deferral Projects. SCE to provide an active spreadsheet that calculates all LNBA metrics used in the project prioritization process (if different than values in the spreadsheet previously listed. Verification: IPE to verify that LNBA values are developed using a methodology that is the same as the one described by SCE. IPE to verify results are the same as those included in the DDOR and project ranking process. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		prioritization metrics and components.
19	Compare 2024 forecast and actuals at circuit	Perform comparison of forecasted and actual loads for all distribution circuits excluding circuits with load transfers.	8/29/25	Forecasted peak load data for 2024 from the 2024-25 DIDF cycle and recorded peak load

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
	level for all distribution circuits	Roles: SCE to demonstrate comparison of 2024 actual loads (as recorded and as adjusted) against the forecasted 2024 load values from the 2024-25 DIDF for each of the comparisons listed above for all circuits excluding those with transfers. Verification: IPE to review SCE demonstrated process, values and compare differences and review comparison data for all circuits analyzed. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DIDF.		data for 2024 from the 2025-26 DIDF for all circuits. Comparison data for all circuits analyzed.
20	Analyze known load tracking dataset and verify the calculation of	The IPE to calculate the metrics mentioned on pages 31 and 32 of the 2023 IPE Post-DPAG Report and verify against the metrics calculated by the utility that are provided in	8/23/24	Confidential version of the known load tracking dataset included in their 2025 GNA-DUPR filing.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
	known load metrics	their narrative related to the known load tracking dataset included in the GNA-DDOR report. The IPE to review the tracking data format, definitions, and processes and reporting that the utility plans to use in the 2025/26 DIDF cycle and make recommendations for changes based on discussions with SCE. The data to be provided by SCE will include known load and pending load data Roles: SCE to provide the confidential version of the known load tracking dataset included in their 2025 GNA-DUPR filing. SCE to also provide information on how they calculated the metrics (for example, Excel workbook showing the formula used for calculating the metrics or something similar) that were included in their narrative of the known load tracking dataset. Verification:		Description of the tracking data set included in their 2025 GNA-DUPR filing. Information on the calculation of metrics (Excel workbook showing the formula used for calculating the metrics or something similar) that were included in their narrative of the known load tracking dataset.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE to analyze the known load tracking dataset provided in the 2025 GNA-DUPR filing and verify the known load metrics calculated by the utility. Validation: IPE to review the approach and process used by the utility to calculate the metrics using known load tracking dataset.		

OTHER IPE WORK

21	Optional - Review plan for changes to the planning process for the next cycle (2025/26 DIDF) (skipped, no longer required)	In this optional step, the IPE will review the planned changes to the planning process in response to the 2024 DIDF reform or any decisions from the High DER Phase 1-Track 1 Proceeding. The data/information required for this step will be determined based on discussions with SCE.	N/A	
22	Review implementing of planning standard and/or planning	No further review is planned for the 2024/2025 DIDF cycle	N/A	

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
	process (skipped, no longer required)			
23	Review list of internally approved capital projects (skipped, no longer required)	No further review is planned for the 2024/2025 DIDF cycle.	N/A	
24	Respond to and incorporate DPAG comments	Include in Final IPE Report.	As needed.	
25	Track solicitation results to inform next cycle (skipped, no longer required)	Part of IPE Post-DPAG Report follow-on activities in coordination with the IE.		
26	Treating confidential material in the IPE report	Confidentiality – the following steps will be followed to ensure that the IPE Reports treat confidential material consistent with the rules and procedures of the CPUC. The dates provided for these steps are tentative and will be finalized based on discussions with SCE.		SCE requires a list of documents and data the IPE intends to use within their report so that SCE can have adequate time to analyze data and perform confidentiality redactions. The data/documents

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		a. The IPE will hold an early meeting with IOU (and potentially the ED) to discuss process for SCE to flag those items they intend to request Confidentiality treatment and on what basis. IPE may provide feedback to ED in lieu of having the ED attend the meeting with the IOU and IPE. Discussion to be held by September 15. b. Date: October 20, 2024 - The IOU will review all the documents² sent to the IPE for the V&V process for confidential information and highlight any information (in addition to information that is already highlighted) that is confidential. The IOU will also develop an equivalent set of documents with the confidential information redacted. At the end of this process, there should be a set of confidential documents that can be included as a part of the confidential		need to be provided in a reasonable amount of time for SCE to provide both public and confidential versions of documents by October 22, 2024, and comments on the draft report by November 3, 2024.

² Documents refers to any document provided to the IPE by the IOU that was not included in the IOU's public version of the GNA/DDOR reports. These documents will be included as attachments to the body of the IPE report as required by a CPUC ruling.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		IPE DPAG report and a set of public documents. c. IPE will provide the confidential version of the body of the draft IPE Report to the IOU by <u>October 20, 2025</u> (the body of the report to include all but the documents provided in previous item) for final IOU confidentiality review. d. IOU checks the draft confidential report for confidentiality and correctness and provides their comments/markups by October 30, 2025. e. After review and signoff, the IPE produces the final confidential and draft reports by November 3, 2025. f. IOU requests CPUC confidential treatment using standard procedures. g. IOU files public version of the IPE report based on the schedule provided		

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
		by the CPUC – DIDF Advice Letters submitted – <u>November 6, 2025</u> h. IOU files revised public report if CPUC rejects any requests for confidential treatment; otherwise, process is complete, and no further action is needed.		
27	Review Methodology used for Prioritization of Planned Projects	Perform verification and validation of the process, if any, used by utilities to prioritize planned projects for execution. Roles: Utility to provide a description of the process, if any, used by utilities to prioritize planned projects for execution. Utility also to provide the results of the prioritization, if applicable. Verification and Validation: The verification and validation process will be determined after discussions with the utility.	Late September/Early October	TBD

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025/26 DIDF Cycle	Target Timing	Data/Information Requirements
28	Review Project Execution Tracking Data and Metrics	Perform verification and validation of the project execution tracking data. Roles: Utility to provide the project execution tracking data. Verification and Validation: The verification and validation process will be determined after discussions with the utility.	Late September/Early October	TBD

Appendix A CPUC 4/13/20 Ruling Excerpts

R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

Attachment A

Listing of Schedule and IPE-Specific Reforms for the 2020-2021 DIDF Cycle

1. IPE-specific reforms for the 2020-2021 DIDF Cycle are implemented within the IPE Scope of Work presented in Attachment B.
2. IOU contracts with the IPE for the full scope of work identified in Attachment B shall be executed by the IOUs to allow for IPE Plan development to begin as soon as possible, ideally on or before **April 17, 2020**.
3. The IOUs shall work with the IPE and Energy Division to develop IPE Plans specific to each IOU such that the IPE can submit the Draft IPE Plans to Energy Division for review on or before **May 15, 2020**.
4. The IPE scope of work may be modified by Energy Division as needed for the IPE to successfully complete each assignment. The IOUs will promptly submit a Tier 1 Advice Letter to notice changes in scope should a scope change differ significantly from the scope described in Attachment B. Minor changes should not necessitate an Advice Letter filing.
5. As required by Energy Division on an annual basis, Pre-DPAG and Post-DPAG activities may include workshops; new, re-opened, suspended, or modified working groups (e.g., Distribution Forecast Working Group); and IOU presentations and deliverables.
6. During the Post-DPAG period and in consultation with the IPE, Energy Division may identify exemplary GNA/DDOR documentation components, analytical approaches, or data strategies implemented by one or more IOUs and require that each IOU implement the reform in future DIDF cycles.

(end of Attachment A)

R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

Attachment B
IPE Scope of Work for DIDF Implementation

Term

- January 1st each year to July 31st the following year with the term subject to update by Energy Division if needed to support each DIDF cycle.

Pre-DPAG Period

- Develop an **IPE Plan** for each IOU describing the GNA/DDOR review process and detailed approach to Verification and Validation of all data used by the IOUs to prepare their DIDF filing materials.
 - Verification and Validation will include a thorough investigation of the following IOU processes, among others:
 - Collecting circuit loadings and performing weather adjustments;
 - Determining load and DER annual growth on the system level;
 - Disaggregating load and DER annual growth to the circuit level;
 - Checking sum of all disaggregated load and DERs against system-level values;
 - Adding incremental known loads to circuit level forecasts;
 - Developing load, DER, and net load profiles and determining net peak loads;
 - Adjusting for extreme weather;
 - Comparisons to equipment ratings to determine if ratings will be exceeded;
 - Incorporating load transfers, phase transfers, correcting data errors;
 - Compiling GNA tables showing need amount and timing; and
 - Following the IOU's planning standard and/or planning process.
 - GNA/DDOR report review will include an in-depth analysis of the following IOU steps, among others:
 - Developing recommended solutions (planned investments);
 - Implementing the IOU's planning standards and/or planning process;
 - Estimating capital costs for planned investments;

- 1 -

R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

- Developing list of candidate deferral projects through application of screens (timing and technical);
 - Developing operational requirements;
 - Prioritization of candidate deferral projects into tiers;
 - Calculating LNBA values; and
 - Comparing prior-year forecast and actuals at circuit level for candidate deferral projects.
- Work directly with the IOUs and Energy Division to develop draft plans as needed. Development of the draft IPE Plans may include, among other activities:
 - Meeting with the IOUs and Energy Division to identify and understand each business process and tool used to complete their GNA/DDOR filings.
 - Facilitate or participate in stakeholder workshops to receive feedback on the IPE Plans.
 - Review and incorporate comments in the final IPE Plans.
 - Submit final IPE Plans to Energy Division and the IOUs with recommendations for future improvements to the plans.
 - Other technical support assignments as defined by Energy Division to ensure the IPE and Energy Division will receive from the IOUs the data and cooperation necessary to complete the required evaluation of the GNA/DDOR filings.

DPAG Period

- Participate in all workshops and meetings during the DPAG period. Prepare and deliver presentations or handouts as requested by Energy Division (*e.g.*, final IPE Plan presentations).
- Develop an *IPE Preliminary Analysis of GNA/DDOR Data Adequacy* for all three IOUs.
- Review any comments on the preliminary analysis that may be received and discuss the results with Energy Division.

R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

- Facilitate meetings with Energy Division and the IOUs to correct data inadequacies and prepare further documentation and provide technical support as needed.
- Fully implement each IPE Plan as defined in the final IPE Plans.
- Develop an ***IPE DPAG Report*** for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes.
- Submit the draft reports to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included or to clarify specific details.
- Circulate the final IPE DPAG Reports to stakeholders (public and confidential versions).
- Other technical support assignments as defined by Energy Division to ensure the DPAG process is successfully completed.

Sample Size

- The scope of review conducted by the IPE for each IOU process may encompass the full set of circuits/projects or a subset/sample of circuits or projects. Where sampling is determined to be appropriate by the IPE in consultation with Energy Division, the size of the sample set for each case will be determined by the IPE based on the application of engineering judgement.

Post-DPAG Period

- Develop a single ***IPE Post-DPAG Report*** covering all three IOUs; comparing their current and prior filings; evaluating DIDF DER procurement, operational, cost, and contingency planning outcomes; reviewing IOU compliance; and making recommendations for process improvements and DIDF reform.
- Coordinate with and support the Independent Evaluator (IE) with IE activities and the development of IE reports as needed.
- Submit the draft report to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included.

R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

- Submit the final report to Energy Division and prepare public versions as needed.
- Support Energy Division with their review of DIDF reform comments, including comments on any IPE tasks.
- Support Energy Division's review of RFO materials and RFO outcomes.
- Attend RFO and procurement meetings and provide technical support as requested by Energy Division.
- Coordinate with the Independent Evaluator to support their evaluation and provide technical support at the discretion of Energy Division.
- Other technical support assignments as defined by Energy Division to develop and evaluate potential DIDF reforms and track and evaluate deferral opportunities that may be subject to ongoing review in other proceedings (e.g., pursuant to General Order 131-D).

List of IPE DIDF Deliverables

1. ***IPE Plan*** for each IOU describing the GNA/DDOR review process and approach to Verification & Validation for the underlying data.
2. ***IPE Preliminary Analysis of GNA/DDOR Data Adequacy*** for all three IOUs.
3. ***IPE DPAG Report*** for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes.
4. ***IPE Post-DPAG Report*** covering all three IOUs, comparing their filings, reviewing compliance, and making recommendations for process improvements and DIDF reform.

(end of Attachment B)

Appendix B Updated Scope of Work Dated March 4, 2025

Proposed IPE Scope of Work (Draft)

Proposed Changes to Current Scope of Work

Current IPE Scope	Recommendations
Step 1 - Collect 2024 Actual Circuit Loading and adjust/normalize for weather as needed	Keep in future cycles
Step 2 - Determine Load and DER Annual Growth on System Level	Keep in future cycles
Step 3 - Disaggregate Load and DER Annual Growth to the Circuit Level	Keep in future cycles
Step 3a - Check sum of all disaggregated load and DERs same as CEC IEPR System level values	Keep in future cycles
Step 4 - Add Incremental Load Growth Projects to Circuit Level Forecasts (those loads not in CEC forecast)	Keep in future cycles
Step 5 - Convert DER growth load to 8760 or 576 profile as needed	Recommend skipping unless process changed.
Step 5 - Convert peak of load to 8760 or 576 profile as needed	Recommend skipping unless process changed.
Step 5 - Convert base forecast and weather normalization adjustment to 8760 or 576 profile as needed	Recommend skipping unless process changed.
Step 6 - Derive net load profile	Recommend skipping unless process changed.
Step 7 - Determine net peak load	Recommend skipping unless process changed.
Step 8 - Adjust for extreme weather	Keep in future cycles
Step 9 - Initial comparison to equipment ratings to determine if ratings exceeded	Recommend skipping unless process changed.
Step 10 - Evaluate no cost solutions - incorporate load transfers, phase balancing, correct data errors	Recommend skipping unless process changed.
Step 11 - Comparison to equipment ratings to determine if ratings exceeded	Recommend skipping unless process changed.
Step 12 - Compile GNA tables showing need amount and need timing, etc (consistent with IOU's documented planning standards and/or planning process)	Keep in future cycles
Step 13 - Develop Recommended solution and generate list of Planned Investments (follow the IOU's documented planning standards and/or planning process)	Keep in future cycles

Step 14 - Estimate capital cost for candidate deferral projects	Eliminate
Step 15 - Development of Candidate Deferral Projects list through application of screens (timing and technical)	Eliminate
Step 16 - Development of operational requirements for CDO (daily, monthly, annually, etc)	Eliminate
Step 17 - Prioritization of Candidate Deferral Projects into Tiers	Eliminate
Step 18 - Calculation of LNBA ranges and values for all planned projects.	Eliminate
Step 19 - Compare 2023 Forecast and Actuals at Circuit Level [proposed change would increase from ~10% of circuits to include all circuits if possible]	Keep in future cycles
Step 20 - Analyze known load tracking dataset and verify the calculation of known load metrics	Keep in future cycles
Step 22 - Review implementing of planning standard and/or planning process	Eliminate
Step 23 - Review list of internally approved capital projects	Eliminate
Step 24 - Respond to and incorporate DPAG comments	Keep in future cycles
Step 25 - Track solicitation results to inform next cycle	Eliminate
Step 26 - Treating confidential material in the IPE report	Keep in future cycles

Proposed Additions to IPE Scope of Work

Decision	New items	IPE Scope
3.1-Allow Utilities to Use Bottom-Up, Known Load Data to Determine Growth	Definition of Reliable Bottom-up Data (as well as, Customer energization Request, Known Load, Pending Load etc.) (Page 42) Note: Decision 3.1 allows Utilities 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. Further, this decision directs that, in years without reliable bottom-up data, total growth should correspond to the forecast amount and not be adjusted downwards.	Annual verification and validation for the use of known loads already being performed as a part of Step 2 of the current V&V process. No new steps required.
3.2 – Require Utilities to Improve Method for Setting Caps on Load Growth from IEPR data.	IOU to work with CEC and CPUC to staff in developing proposals for the method and accounting for discrepancies between the system and circuit level. (Page 43) Decision 3.2 further focuses on developing proposals for the method and accounting for discrepancies between the system and circuit level (forecasts). The forecast at the system level (IEPR) is a coincident peak load forecast and is not necessarily equal to the sum of the peak loads on all the circuits. So, a methodology needs to be devised to develop circuit level forecasts that takes this into account. This decision approves, with one modification, the recommendation to require Utilities to submit Advice Letters proposing how they will improve their methods for setting caps on load growth based on the IEPR forecasts and other data. Utilities shall file Tier 3 Advice Letters. (Page 47)	Verify and validate IOUs' use of methodology for accounting for discrepancies between the system and circuit level load forecasts in the DPP. Annual starting 2025-2026 cycle. Annual verification and validation of methods for setting caps on load growth from IEPR data already covered under Step 2 of the current V&V process. No new steps required.
3.4 – Require Utilities to Expand the DPP Forecast Horizon to Align with IEPR and Expand the Planning Horizon to 10 Years.	To ensure transparency, utilities shall provide a description of the thermal capacity evaluation methodology in the annual GNA report (Page 55)	No new steps required to verify the expanded DPP planning horizon. The current V&V will be extended from 5 years to 10 years. Annual starting 2025-2026 cycle.

3.5 – Require Utilities to Use Scenario Planning to Improve Forecasting and Disaggregation	Workshops to develop scenario planning methodology and process. (Page 59) Utilities shall develop scenario planning capabilities that enable them to: (1) analyze multiple forecasts; (2) identify capacity deficiencies for each scenario and report them in the annual GNA; and (3) develop one investment plan informed by the multiple scenarios and reported in the DDOR or successor filing. (Page 61)	Attend workshop. One Time. Estimated Q1 2025 Verify and validate each DPP scenario and how utilities create one investment plan informed by multiple scenarios in the annual DPEP. Annual starting 2025-2026 cycle. • Develop draft IPE Plan for V&V of scenario planning – Q2 2026 • Finalize IPE plan – Q3 2026 • Perform V&V Q3 2026
3.6 - Require Utilities to Improve Disaggregation Methodology for Load Growth	Require Utilities to Improve Disaggregation Methodology for Load Growth (Page 62) This decision adopts the recommendation to require Utilities to improve disaggregation methodologies for load growth and distributed energy resources but delays implementation to the 2027 GNA and the 2026-2027 DPP cycle. To track progress toward improved disaggregation in the interim, Utilities shall report annually in the GNA on the development of advanced disaggregation methodologies and present these at the annual Distribution Forecast Working Group workshops or successor workshops. (Page 65)	Verify and validate the improved disaggregation methodology. Annual starting 2026-2027 cycle. Q3 2027. • Develop draft IPE Plan for V&V of improved disaggregation methodology – Q2 2027 • Finalize IPE plan – Q3 2027 • Perform V&V Q4 2027
3.7 - Require Utilities to Create Pending Loads Category in the DPP	Utilities are directed to provide pending load data and include the source of the data in the annual known load tracking filing, as part of the GNA/DDOR or successor report and orally reported during the DPAG or successor workshop (Page 76)	Attend workshop. One Time. Estimated Q1/Q2 2025 Verify and validate pending load data and source in annual reports and DPAG or successor workshop. Annual starting 2025-2026. • Develop draft IPE Plan for V&V of Pending Loads – Q2 2026 • Finalize IPE plan – Q3 2026 • Perform V&V Q3 2026

3.8 – Require Utilities to Develop Prioritization Methods Beyond the Current Consideration of Project Need Dates	Utilities to report how projects identified throughout the distribution planning horizon have been prioritized for execution. This decision also requires inclusion of this information in the annual GNA/DDOR or a successor report instead of the previously required Advice Letter (83)	Verify and validate the process used by utilities to prioritize projects for execution. Annual starting 2024-2025 cycle. • Develop draft IPE Plan for V&V of prioritization methodology – Q2 2025 • Finalize IPE plan – Q3 2025 • Perform V&V Q3 2025
3.9 – Require Utilities to Consider Distribution Planning Results in Other Distribution Work	Utilities to consider distribution planning results in other distribution work aka Integrated planning (Page 83) A workshop shall be held by Utilities during the third quarter of 2025 to present Utility proposals for integrated planning and solicit feedback from stakeholders on issues presented, including cost containment considerations. A second workshop shall be held by Utilities no more than eight weeks following the first workshop to present updated proposals based on feedback from the first workshop. (Page 86)	Attend workshop. One Time. Estimated Q3/Q4 2025. Verify and validate that integrated planning projects meet the established requirements. Annual starting 2026-2027. • Develop draft IPE Plan for V&V of integrated distribution planning – Q2 2027 • Finalize IPE plan – Q3 2027 • Perform V&V Q3 2027
3.11 – Require Utilities to Prepare a Load Flexibility DPP Assessment	Require Utilities to Prepare a Load Flexibility DPP Assessment. (Page 98)	Review EIS Part 2 studies and attend workshop. One Time. Estimated Q1 2026.
3.15 – Require Utilities to Include Metrics to Evaluate Equity in Utility Distribution Plan Reporting	Require Utilities to Include Metrics to Evaluate Equity in Utility Distribution Plan Reporting (Page 119) The Commission clarifies that while these metrics are requested for evaluation purposes, there is no framework wherein equity metrics are used for forecasting or planning distribution. The intention of this proposal is an annual evaluation of equity in distribution planning and does not involve modifying the planning process based on equity considerations. (Page 123)	Support the ED and the IOUs in finalizing and standardizing the tracking and reporting of the Equity Metrics. One Time. Estimated Q2 2025. Verify and validate equity metrics calculated by the utilities and reported by the utilities annually. Annual starting 2025-2026 DPP cycle. • Develop draft IPE Plan for V&V of equity metrics – Q2 2026 • Finalize IPE plan – Q3 2026 • Perform V&V Q3 2026

3.16 – Require Utilities to Include Metrics to Track Project Execution in Utility Distribution Plan Reporting	Require Utilities to Include Metrics to Track Project Execution in Utility Distribution Plan Reporting (Page 123) *also see Table 12 and Table 13. Table 12 * Additional Details for All Ongoing and Prior Three Years Completed Distribution Capacity Projects Table 13* Additional Project Execution Tracking Data	Support the ED and the IOUs in finalizing and standardizing the tracking and reporting required to track project execution based on Table 12, 13, and the requirements of R24-01-018 (Appendix B - Decision Establishing Target Energization Time Periods And Procedure For Customers To Report Energization Delays). One Time. Estimated Q2 2025 Verify and validate the project execution data and metrics submitted by the utilities. Annual starting 2024-2025 DPP cycle. • Develop draft IPE Plan for V&V of project execution metrics – Q2 2025 • Finalize IPE plan – Q3 2025 • Perform V&V Q3 2025
3.18 - Require Utilities to Facilitate Better Coordination and Data Sharing Between the DPP and Transportation Electrification Planning	Require Utilities to Facilitate Better Coordination and Data Sharing Between the DPP and Transportation Electrification Planning (Page 135)	Verify and validate how TEPP outputs are used in DPP. Annual starting 2025-2026 earliest. • Develop draft IPE Plan for V&V of TEPP coordination – Q2 2026 • Finalize IPE plan – Q2 2026 • Perform V&V Q3 2026

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Appendix C Documents and DPAG Q&A

The IPE received many sets of data from SCE during the review. Listed below are the documents provided to the IPE during the course of the review. In many cases these data sets are presentations (Power Point) that were used in demonstrations of the various business processes in the IPE Plan. In addition, numerous spreadsheets and PDFs and/or Word documents were also provided. These actual documents are provided separate from the body of this report due to their size.

Two lists of documents that were provided to the IPE by SCE are shown below. One lists the set of documents that are considered Public since they do not contain any confidential information. The second list contains all of the documents that are declared confidential and are not available to the public.

C.1 List of Documents Provided - Public Set



GRC (1)_Public.pdf



GRC_Workpapers (1)_Public.pdf



R2106017-SCE 2024 GNA-DDOR Report-Public.pdf

C.2 List of Documents Provided - Confidential Set

-  Confidential_2021 AAFS 4 plus FSSAT-SIP for 2022 Local Reliability Scenario annual FZ-TAC (1)_Confidential.xlsx
-  Confidential_2022 IEPR AAEE-AAFS Annual Impacts (1)_Confidential.xlsx
-  Confidential_2022 IEPR TAC to Retail Scailing Factor (1)_Confidential.xlsx
-  Confidential_2023 IEPR Load Growth_Total Consumption_Final Version.xlsx
-  Confidential_2023.04.17 SCE MDHD PEV Stock and GWh Data Request - CEC (1)_Confidential.xlsx
-  Confidential_2024 DSP CEC 2022_2023 IEPR DER Forecasts_Final_Confidential.xlsx
-  Confidential_2024 SCE DDOR_Confidential (1).xlsx
-  Confidential_2024 SCE GNA_Confidential (1).xlsx
-  Confidential_2024 -Step 19 Circuit Data Updated Updated_Confidential.xlsx
-  Confidential_2025 DSP CEC 2023 IEPR DER Forecasts_IPEV3.xlsx
-  Confidential_AAEE 2022 Update AAEE Slicer forecast_All (1)_Confidential.xlsx
-  Confidential_CA_Planning_Library_2023_IEPR_Plug-in_Electric_Vehicle_Energy_Forecast_ada.xlsx
-  Confidential_CED2022_NONRES_ES (1)_Confidential.xlsx
-  Confidential_CED2022_NONRES_PV (1)_Confidential.xlsx
-  Confidential_CED2023_NONRES_ES.xlsx
-  Confidential_CED2023_NONRES_PV.xlsx
-  Confidential_CEDU2022_SCE_Workbook (1)_Confidential.xlsx
-  Confidential_Copy of PendingLoad_MWh_Report_09112025.xlsx
-  Confidential_Customer-Owned Subtrans Substations (1)_Confidential.xlsx
-  Confidential_IEPR2023_DER_System_EV_Energy_20241211.csv
-  Confidential_IEPR2023_DER_System_MDHD_Energy_20241211.csv
-  Confidential_LOAD_DER_SHAPE_FILE_1_2024_20231121 (1)_Confidential.csv
-  Confidential_LOAD_DER_SHAPE_FILES_2_2024_20231206 (1)_Confidential.csv
-  Confidential_PendingLoad_MWh_Report_09112025.xlsx

List of Documents Provided - Confidential Set Continued

-  Confidential_PY25 Shaping_V2_FGG.xlsx
-  Confidential_PY25_Projected_vs_Actual_SP_FINAL (1).xlsx
-  Confidential_SCE Data Request - PV Capacity for SF New Homes 2023 CEC Forecast.xlsx
-  Confidential_SCE LDMDHD PEV Stock and GWh Data Request v.9.10.24 (1).xlsx
-  Confidential_SCE.(June).IPE_Steps 2-3a (Final).pptx
-  Confidential_SCE.PY25.IPE_Step 19.pptx
-  Confidential_SCE.PY25.IPE_Step 20.pptx
-  Confidential_SCE.PY25.IPE_Step 27.pptx
-  Confidential_SCE.PY25.IPE_Step 28.pptx
-  Confidential_SCE.PY25.IPE_Step13 (1).pptx
-  Confidential_SCE.PY25.IPE_Steps 1_8_4 (Final) Updated 202510.pptx
-  Confidential_SCE_Load_System_DCFC_Peak_20241211.xlsx
-  Confidential_SCE_Load_System_EVGO_Peak_20241211.xlsx
-  Confidential_SCE_Load_System_SCE_Peak_20241211.xlsx
-  Confidential_SCE_Load_System_Tesla_Peak_20241211.xlsx
-  Confidential_Selfgen_2023_12_12_Planning_Library_ada.xlsx
-  Confidential_Step 13 Circuits_IPE.xlsx
-  Confidential_TEGR2024_DER_System_PortMDHD_Energy_20241211.xlsx
-  Confidential_TEGR2024_DER_System_PortShorepower_Energy_20241211.xlsx
-  Confidential_TEGR2024_DER_System_Truckstop_Peak_20241211.xlsx
-  Confidential_TN254247_20240131T141810_CED 2023 Baseline Forecast - SCE.xlsx
-  Confidential_TN257109_20240619T124141_CED 2023 Local Reliability LSE and BAA Tables - Corrected.xlsx

C.4 Post DPAG Questions and Responses from SCE are included on the following pages.

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

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

R.21-06-017

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E)
RESPONSES TO DPAG QUESTIONS AND COMMENTS

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Dated: **October 6, 2025**

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

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

R.21-06-017

SOUTHERN CALIFORNIA EDISON COMPANY’S (U 338-E)
RESPONSES TO DPAG QUESTIONS AND COMMENTS

Pursuant to the March 6, 2025 *Administrative Law Judges’ Ruling Setting Schedule For The 2025-2026 Distribution Investment Deferral Framework Cycle*, Southern California Edison Company (“SCE”) respectfully submits the attached responses to participant questions and comments regarding SCE’s Distribution Planning Advisory Group (“DPAG”) meeting.

Respectfully submitted,

WILLIAM YU

/s/ William Yu

By: William Yu

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October 6, 2025

Attachment

SCE's Responses to DPAG Questions and Comments

Responses to Questions Regarding SCE's Sept. 19, 2025 DPAG Workshop

Oct. 6, 2025

1. EV Load Forecasting Methodology / MDHD EV Forecast Details

For the 2024–2025 plan year, SCE Distribution Planning Process (DPP) incorporated three primary components to forecast TE load, as detailed below:

1. Disaggregation of IEPR EV Forecasts

SCE disaggregated the IEPR EV forecasts for both light-duty (LD) vehicles and medium-/heavy-duty (MDHD) trucks, consistent with the approach outlined in SCE's 2025 GNA/DUPR Report (pp. A-14 to A-18).

- **LD EVs:** Disaggregation was performed using propensity models, with household income serving as the primary indicator of EV adoption.
- **MDHD EVs:** Disaggregation leveraged a separate propensity model, targeting fleet depot charging.

2. Tracking of Commercial EV Charging Service Requests

SCE accounted for service requests from commercial EV charging customers. These requests primarily involved LD Fast Charging sites but also included some applications of MDHD vehicles, electric ships, school and transit buses, hydrogen fueling stations, electric locomotives, and transport refrigeration units. Customer service requests that reached partial or full submittal status were considered as known EV loads. Because these load growth projects primarily represent commercial charging needs for LD EVs (as distinct from the residential charging demand) and mobility-based charging needs for MDHD EV, they were treated as incremental to the IEPR EV forecast.

3. Incorporation of Pending EV Load Indicators

As an early implementation of the pending loads, SCE included forecasted EV-related load growth that has not yet materialized as formal customer requests but is supported by credible planning indicators into its base case. These loads include commercial EV vendor forecasts, Port of Long Beach electrification, truck stop electrification, and SCE fleet electrification plan. They were also treated as incremental to the IEPR EV forecast because these forecasted loads also represent mobility-based charging needs for EVs. This early implementation of pending loads should not be conflated with the full implementation

criteria that will be established in future planning cycles, subject to CPUC decision-making.

SCE's IEPR EV disaggregation methodology primarily assigns the total annual energy consumption to EVs' stationary charging locations, such as home charging for LD EVs and depot charging for MDHD EVs, to align with IEPR's vehicle-count-based forecast. To capture capacity needs, daily charging load shapes are applied to distribute this energy across the hours of a typical day, which provides a proxy for estimating peak load impacts.

When EVs charge away from their base location (e.g., LD EVs at public DCFC sites or MDHD EVs at corridor charging stations), that energy use is incremental to the IEPR forecast. However, this does not lead to overstated capacity needs, because each charging event imposes a capacity impact on the grid at the location it occurs. Utilities must therefore plan for these potential peaks, which are driven by the charger count at each site.

As a result, while the EV energy forecast may appear to exceed IEPR totals, this is a necessary modeling choice to ensure the grid is adequately prepared to meet peak demand, wherever and whenever it occurs.

Verbal Question: How does SCE incorporate known EV loads relative to the CEC's IEPR forecast? Are they treated as incremental?

Please refer to the methodology outlined above.

PAO 3e. How does SCE coordinate with the California Energy Commission (CEC) to determine if specific known loads or categories of known loads are incremental to the IEPR forecast? Please specify any public processes, workshops, filings, etc. that SCE uses to coordinate with the CEC.

SCE maintains regular contact with CEC forecasting staff to discuss forecast methodologies and data inputs. SCE participates in CEC-hosted public workshops, such as the IEPR Commissioner Workshops on Energy Demand Forecast Inputs and Load Modifier Scenario Updates and Demand Analysis Working Groups (DAWG), which provide opportunities to present SCE's forecasting approach and receive feedback from CEC staff. Additionally, SCE shares the known load data included in the annual GNA/DUPR filing, provides supplemental information, and answers questions as requested by the CEC, all with the goal of enhancing transparency and alignment between SCE's distribution planning and the CEC's system-level forecasts.

PAO 5h. Does SCE track deferrals for MDHD loads? If so, what percentage of the TE load deferrals are MDHD loads?

SCE does track deferrals for MDHD loads. Out of 377 total TE load deferrals, 132 are MDHD loads, which is approximately 35% of all TE load deferrals are attributed to MDHD projects.

PAO 6. Is the IPE's assumption correct that SCE uses its bottoms up forecast to disaggregate the IEPR MDHD load as described on slide 60? This would assume that SCE does not exceed the IEPR MDHD load, but merely spatially allocates the IEPR MDHD load to feeders.

Please refer to the methodology outlined above.

2. Known Load Vetting Process

Verbal Question: How does SCE vet interconnection applications to avoid double-counting speculative or duplicate requests?

SCE requires customers to submit detailed, site-specific documentation, such as load schedules, site locations, plot plans, and tract maps, as part of the application submittal process. The effort and specificity involved make it unlikely that customers would submit duplicate applications without genuine intent to pursue distinct projects.

SCE maintains a centralized database of customer load growth inputs. If engineering teams identify identical or highly similar documentation across applications, they conduct follow-up reviews and engage applicants to confirm whether the submissions represent separate developments or inadvertent duplicates. This validation ensures infrastructure planning is not duplicated for the same load across multiple sites.

To support customers evaluating multiple potential project sites, SCE offers the option to request an Engineering Analysis Report, enabling informed decisions and reducing unnecessary submissions.

PAO 3b. What is the minimum level of documentation (i.e., partial application submittal) for which SCE qualifies a load as a known load?

The minimum documentation required for partial submittal includes:

- Customer Project Information System (CPIS) entry
- Detailed demand estimate
 - Nature of load (type and hours of operation)
 - Building square footage (Spec buildings)
 - Peak demand
- Energization date

- With phasing if applicable
- Site plan or plot plan
- Single Line Diagram (SLD)

PAO 3c. How does SCE validate the requested service amount for incremental known loads?

SCE validates the requested service amount for incremental known loads by assessing the documentation provided by customers. The validation approach varies depending on the type and completeness of the documentation submitted.

PAO 3f. What data and/or studies does SCE publish that would allow stakeholders to review incremental known loads?

Known loads (both embedded and incremental) are driven by customer service requests, not by studies. SCE submits the Known Load Tracking Report, which includes both embedded and incremental known loads, as part of its annual GNA and DUPR filings. The report is publicly available and included in filings served to the official service list.

3. EV Developer Application Patterns

Verbal Question: Do EV charging developers submit more applications than needed to hedge against cancellations?

See below.

PAO 3d. Given that developers sometimes submit multiple applications for one project, how does SCE validate that it is not planning for the same load for multiple sites?

As part of the application submittal process, customers are required to provide detailed and site-specific documentation, including load schedules, site locations, plot plans, tract maps, and other supporting materials. The level of effort and specificity involved in preparing these submissions makes it unlikely that a customer would submit duplicate applications without a genuine intent to pursue multiple distinct projects. In cases where applications contain identical or highly similar documentation (e.g., load schedules, plot plans), SCE engineering teams will conduct follow-up reviews and engage directly with the applicants to clarify whether the submissions represent separate developments or inadvertent duplicates. This validation process ensures that SCE does not plan infrastructure for the same load across multiple sites.

4. Residential Load Growth Attribution

Verbal Question: Is the sharp increase in residential known loads driven by EV adoption or general housing demand?

The increase in residential known loads is driven by general housing demand.

5. TE Deferral vs. Project Size Correlation

Verbal Question: Why are TE projects showing high deferral rates? Is there a correlation with project size?

Deferred TE project loads tend to be smaller on average (2.42 MW) and median (1.55 MW) compared to non-deferred TE loads (3.51 MW average, 1.62 MW median). Thus, if there is a correlation, it is that the larger the project size, the less likely it is to be deferred.

PAO 5e. Why do TE known loads show a significantly higher deferral rate than other load types?

TE known loads show a higher deferral rate than other load types because TE projects tend to encounter challenges that increase the risk of schedule delays. These include customer funding readiness, construction timeline, permitting process, land acquisition negotiations, Rule 15 requirements. Additionally, dependencies on incentive programs or customer preparedness further contribute to the complexity and likelihood of deferrals.

PAO 5f. Why do TE known loads show a significantly higher cancellation rate than other load types?

TE Known Loads show a higher cancellation rate than other load types (e.g., Residential, Commercial, Industrial, and Agricultural) due to a combination of market dynamics, infrastructure limitations, and planning challenges. TE projects often involve large service capacity requests on compressed timelines, making them sensitive to delays in permitting, site readiness, and construction. If grid infrastructure upgrades cannot align with customer schedules, or if make-ready work and environmental reviews stall progress, customers may withdraw their requests entirely. Additionally, many TE projects depend on incentive programs and regulatory clarity, which, if paused or uncertain, can lead to cancellations.

ED 3) a) Please further explain the significance of the “Load Components – Annual Values” chart on slide 62 of the DPAG presentation? How is it that in the year 2025 TE loads are ~5X larger than the entire IEPR load growth forecast? Why is IEPR-EV in light blue included in the bar chart stack?

Please refer to the methodology outlined in Question 1.

6. Definitions of Load Categories

Verbal Question: What are the definitions and treatment of pending loads, incremental loads, and embedded loads?

Embedded load refers to load growth categories already captured within the IEPR forecast, such as residential, commercial, industrial, and agricultural sectors. These loads are considered part of the baseline consumption forecast.

Incremental load refers to load growth categories that are not represented or insufficiently captured in the IEPR forecast. SCE treats these loads as additive to the IEPR baseline.

- Cultivation sectors
- Wholesale Distribution Access Tariff (WDAT) projects
- Firm charging
- Temporary load
- EV charging demand based on mobility and grid capacity impacts (not vehicle-count based energy consumption disaggregation).

For the 2024-2025 plan year, pending loads refer to emerging or forecasted load growth that has not yet been formally requested by customers but is supported by credible planning indicators. These include:

- Commercial EV vendor forecasts,
- Port of Long Beach electrification (shore power and cargo handling),
- Truck stop electrification informed by external studies,
- SCE fleet electrification.

This early implementation of pending load should not be conflated with the full implementation criteria that will be established in future planning cycles, subject to CPUC decision-making.

PAO 7. regarding the chat below during SCE's DPAG meeting and slides 61-63, Cal Advocates provides the following clarifications and questions.

- a. Describe the following types of loads, including examples of customer load projects: cultivation, firm charging, load WDAT, and temporary load.**

Cultivation: Any facility explicitly used for the legal, commercial growing of marijuana for sale and/or distribution.

Load WDAT: Load served under the Wholesale Distribution Access Tariff (WDAT), where the customer purchases power directly from the California ISO (CAISO), and the energy is delivered through SCE's distribution system. This arrangement is governed by FERC and applies to wholesale transactions, not retail service.

Firm Charging: A specific type of charging service under SCE's WDAT for energy storage projects. It guarantees firm access to grid energy for charging, meaning the customer has priority rights to charge even during constrained grid conditions.

Temporary Load: A utility-connected source of power provided to a job site to serve the electrical needs of construction equipment during the building of a structure. This load is typically disconnected once permanent service is established.

7. IPE Analysis Update / Clarification on TE/EV Load Forecasting Methodology

Verbal Question: There was confusion between SCE and the IPE on load categorization & whether SCE disaggregates or replaces the IPER medium/heavy-duty EV load with its own bottom-up forecast.

Please refer to the methodology outlined in Question 1

Note that the IPE did not assume that only load growth projects with full documentation submittals qualified as known loads. The IPE recognized that the known load category includes both full and partial submittals.

Further, SCE would like to add in its early implementation of pending loads, emerging and forecasted loads that were not yet requested by customers but were supported by credible planning signals. These included:

- Commercial EV vendor forecasts,
- Port of Long Beach electrification (shore power and cargo handling),
- Truck stop electrification informed by external studies,
- SCE fleet electrification.

These loads were considered pending not due to incomplete documentation, but because they were driven by customer engagement, third-party studies, or internal fleet planning—rather than formal interconnection applications.

It is important to clarify that this was the first implementation of pending loads and should not be confused with full implementation criteria used in future planning cycles.

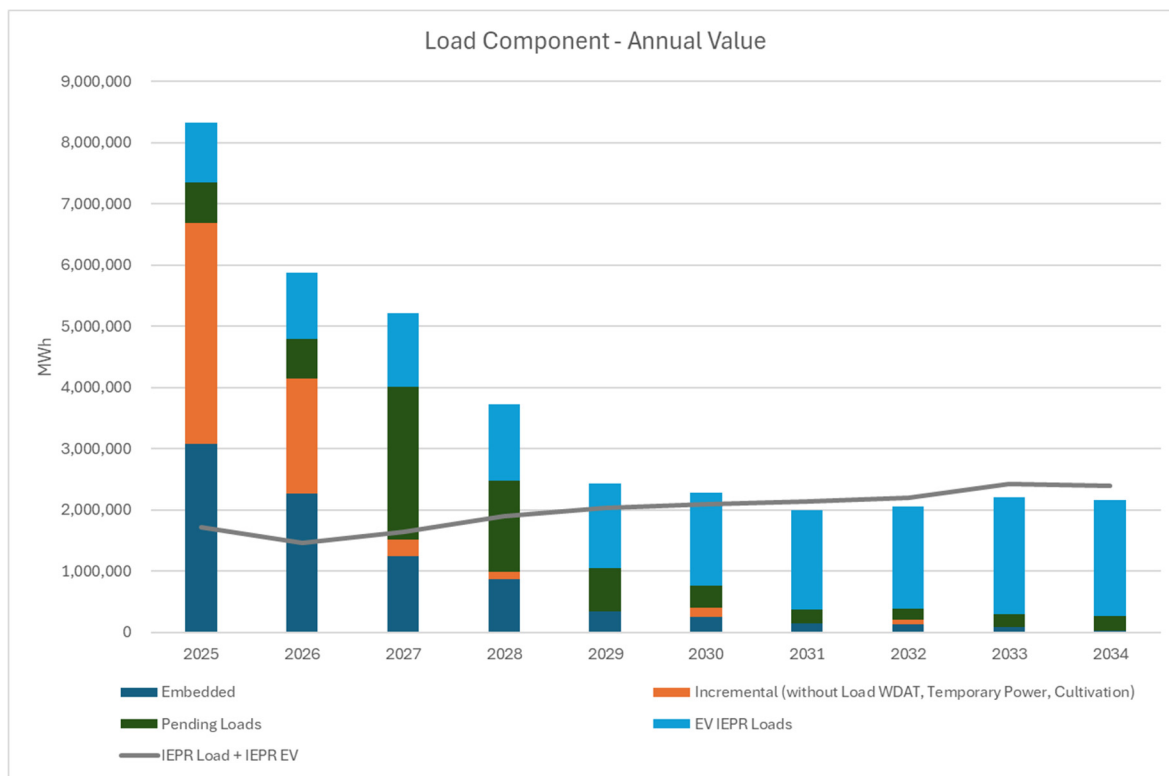
PAO 3. Incremental Known Loads: In its GNA, SCE states, “the IEPR forecast does not account for all types of load growth seen on SCE’s system. . . The load from these

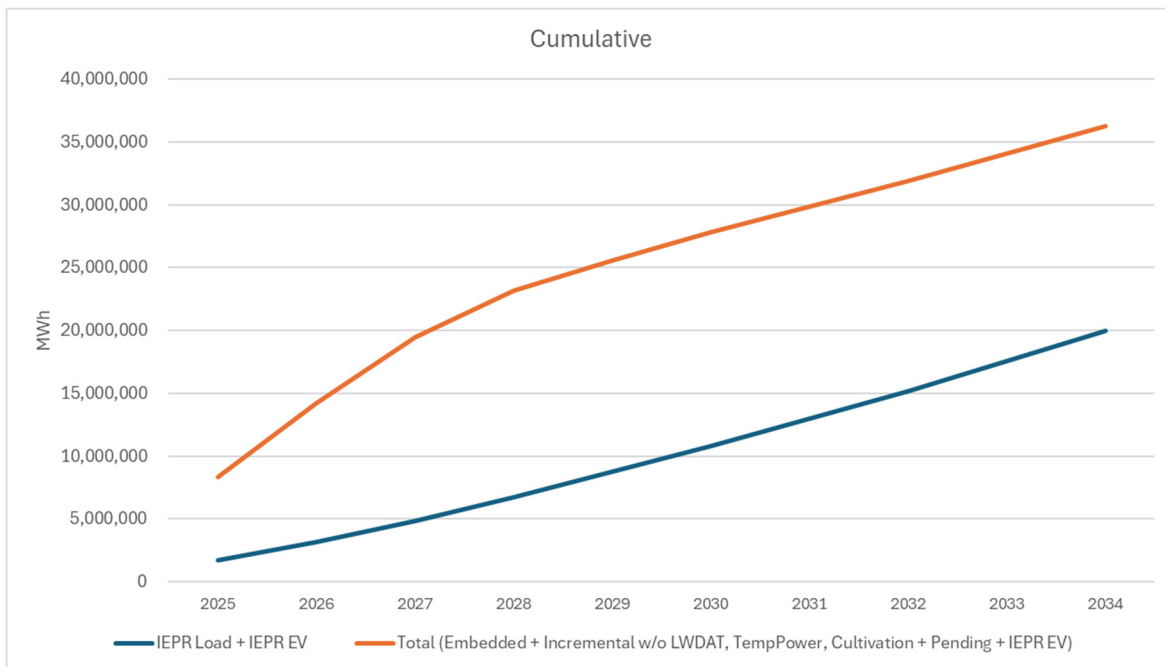
[load growth projects] is added incrementally to the IEPR forecast.” Also, SCE explains that “[load growth projects] determined to be outside the IEPR are allocated in the year of request at the magnitude requested with the diversification factor applied.” Furthermore, SCE categorizes loads based on “IEPR status” as either embedded or incremental.

a. What methodology does SCE use to determine which known loads are incremental to the IEPR?

SCE determines whether a known load is incremental to the IEPR forecast based on its representation and methodology within the IEPR. If a known load category, such as cultivation, Wholesale Distribution Access Tariff (WDAT), firm charging, or temporary load, is not explicitly captured in the IEPR forecast, or if its forecasting approach differs materially, it is treated as incremental. Specifically, the IEPR’s EV forecast is vehicle count based energy consumption and does not fully account for the mobility characteristics of electric vehicles and their associated capacity impacts on the grid. As a result, the charging demand driven by vehicle mobility is considered incremental to the IEPR forecast.

PAO 7b. Could the IPE and SCE analyze and produce graphs (like those in slide 62) showing the comparison of the IEPR load growth vs. SCE’s load growth forecast (annual and cumulative) without cultivation, firm charging, load WDAT, and temporary load?

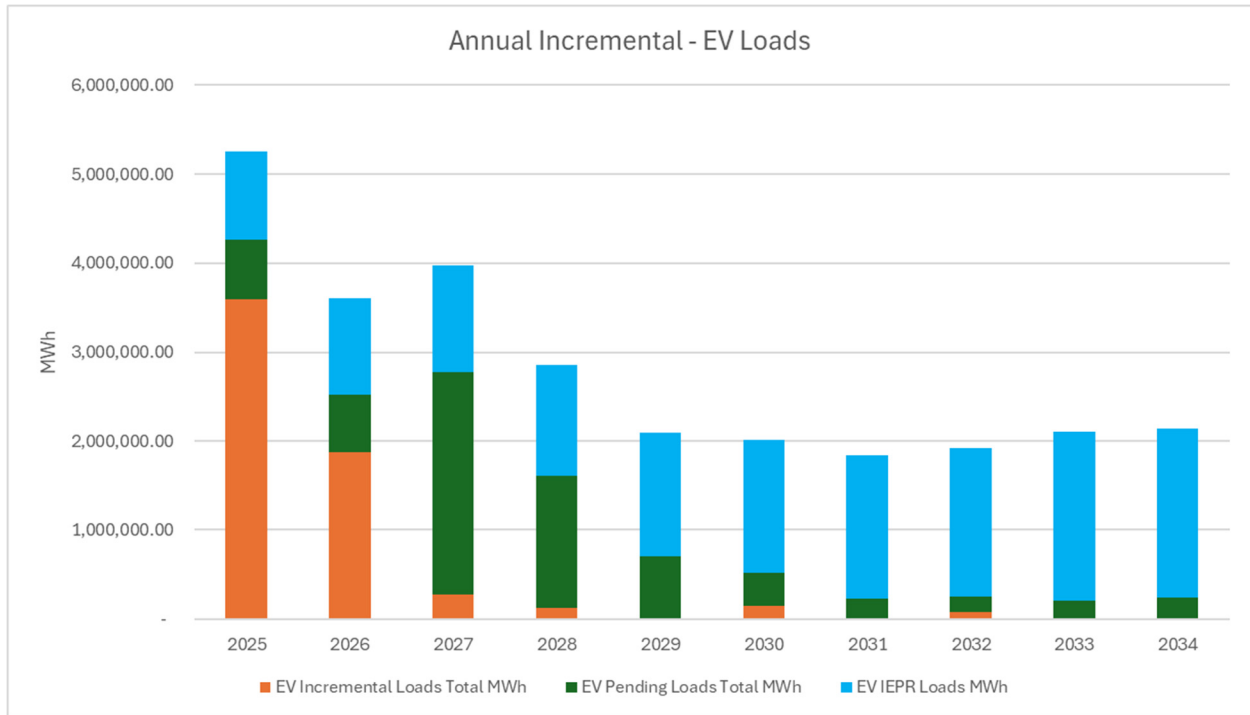




PAO 7c. Once the cultivation, firm charging, load WDAT, and temporary load categories are removed, does SCE’s forecast reconcile with the IEPR over the forecast horizon?

SCE’s embedded known load forecast already exceeds the IEPR 13-year total consumption forecast. Therefore, even after removing incremental load categories, such as cultivation, firm charging, WDAT, and temporary load, the divergence remains.

PAO 7d. Also, once the cultivation, firm charging, load WDAT, and temporary load categories are removed, please show in a graph the annual load for the various types of EV load (incremental EV known loads, EV pending loads, and IEPR EV) to visualize the relative contribution of different EV load categories. "



8. Pending Loads and Incremental Load Definitions

SCE takes this opportunity to clarify how incremental loads, including pending loads, are reconciled with IEPR. SCE does not reconcile incremental known loads and pending loads with the IEPR forecast because, by definition, incremental loads are either not represented or not sufficiently captured within the IEPR. This includes sectors such as cultivation, Wholesale Distribution Access Tariff (WDAT), firm charging, and temporary service, as well as EV charging demand based on mobility and grid capacity impacts rather than vehicle-level energy consumption. As such, these loads are treated as additive to the IEPR forecast.

PAO 4. In its report, SCE states that it “included early implementation of pending loads . . . for the 2024-2025 planning year.”

a. What methodology does SCE use to determine which pending loads are incremental to the IEPR forecast?

SCE determines whether pending loads are incremental to the IEPR forecast by evaluating their representation and methodology relative to the IEPR, consistent with the approach used for known loads. The pending loads SCE included in the 2024-2025 plan year are: commercial EV vendor forecasts, Port of Long Beach electrification, truck stop electrification informed by external studies, and SCE fleet electrification. These loads are

derived from data that reflect operational realities and infrastructure requirements beyond the scope of the IEPR's vehicle-based energy projections. Accordingly, SCE's pending loads included in the 2024-2025 plan year are considered incremental to the IEPR forecast.

b. How does SCE coordinate with the CEC to determine if specific pending loads or categories of pending loads are incremental to the IEPR forecast? Please specify any public processes, workshops, filings, etc. that SCE uses to coordinate with the CEC.

In accordance with the High DER Decision 'D.24-10-030', OP27 requires the following "Beginning with the 2025-2026 Distribution Planning and Execution Process, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) must track and report all known load projects to the California Energy Commission..."

SCE is working on formalizing this process with CEC to commence in 2026, in addition to sharing Known Loads, SCE will include Pending Loads with the mutual goal of transparency of expected loads and to have a more representative CEC forecast of SCE's system.

SCE also notes ongoing High DER workstreams under the Track 1 Decision regarding what IEPR caps are, what it means to exceed such caps, and what the significance of such exceedances are. "Exceeding IEPR" does not necessarily mean SCE thinks IEPR is wrong, but due to methodological differences between local and system level planning, it does not reconcile perfectly for all loads. This discussion will continue in the IEPR caps workstream.

c. How does SCE evaluate the confidence level of its pending loads?

SCE evaluates the confidence level of pending loads based on the quality and completeness of information provided by the customer. Confidence may be further supported by:

- Historical data or established relationships with EV vendors, who have consistently demonstrated a high level of follow-through when requesting capacity.
- External mandates, such as government directives (e.g., Port of Long Beach electrification), which provide strong assurance that the load will materialize.

d. What data does SCE publish that would allow stakeholders to verify if a specific pending load is incremental to the IEPR forecast?

SCE submits the Known Load Tracking Report as part of its annual GNA and DUPR filings. The report also lists pending load included in the annual DPP. As presented in the answer to question 6, SCE determines whether a project (pending or known) is incremental to the IEPR forecast based on load type (whether they are represented or sufficiently captured in

the IEPR forecast or not) rather than evaluating individual projects. Stakeholders can review whether they believe these categories are indeed incremental; SCE had determined that they are.

e. How does SCE forecast MDHD bottom-up load to account for high uncertainty, given the nascency of the MDHD industry?

As a regulated utility, we are obligated to plan for and serve customer load requests in a timely and reliable manner, regardless of the nascency of the MDHD industry. Failure to plan for the full amount of requested load, even if a customer later withdraws, can result in costly last-minute upgrades, missed service deadlines, and ratepayer exposure to expedited buildout costs. While the MDHD sector is still developing, other MDHD loads will continue to materialize in locations with available capacity, allowing us to reallocate resources and maintain system readiness. This flexible, forward-looking approach ensures we meet our regulatory obligations while adapting to evolving customer demand.

SCE identifies that MDHD loads have two drivers: (1) customer-driven - when a customer within that sector has come forward and provided a certain level of information that aligns with our internal framework to assess certainty and assign its corresponding category, it will get treated the same as any type of customer-driven pending load. (2) study-driven - based on multi-phase and multi-year research efforts, reliable sources within relevant industries, regulatory mandates, industry studies, analysis based upon compliance obligations and load growth trends.

For further detail on SCE's proposed framework, please refer to SCE's Pending Loads Advice 5567-E, dated June 27, 2025.

9. Grid Needs

PA01. SCE does not identify the number of grid needs by operating date, as PG&E and SDG&E do. Please provide the count of grid needs by operating date for the 2021- 2025 GNAs, if available. Also, please provide the number of grid needs by operating date in SCE's future GNAs

SCE will provide GNA Needs by Operating Date in future DUPR reports, and includes them below for 2021-2025.

2025 Needs by Operating Date

2025	2026	2027	2028	2029	Total
201	224	144	67	55	691

2024 Needs by Operating Date

2024	2025	2026	2027	2028	Total
94	171	78	99	39	481

2023 Needs by Operating Date

2023	2024	2025	2026	2027	Total
115	114	80	27	10	346

2022 Needs by Operating Date

2022	2023	2024	2025	2026	Total
114	139	37	20	11	321

2021 Needs by Operating Date

2021	2022	2023	2024	2025	Total
95	123	49	5	3	275

10. Planned Investments

PAO 2.SCE identified the following number of planned investments in its 2021,2 2022,3 2023,4 2024,5 and 2025 GNAs. SCE’s planned investments have increased noticeably in the 2025 GNA-DUPR cycle, corresponding with early implementation of pending loads in distribution planning.

- a. What is the annual number of grid needs and planned investments by operating date for 2025-2029 when pending loads are omitted from the forecast?**

This request would require a complete re-execution of the planning process, including redevelopment of the forecast, reassessment of grid needs and re-evaluation of solutions across the system.

SCE objects to this question to the extent SCE does not have readily available information responsive to this question. SCE tracks and provides information consistent with the CPUC’s requirements. SCE does not generate or use in the ordinary course of its operations or records-keeping all the data as requested by this question. As such, this question seeks the creation of new studies, analyses, and/or presentation of data in formats that do not exist. Discovery requests that cannot be answered with existing data are improper and beyond the scope of permissible discovery under Rule 10.1. See, e.g., A.20-06-001 E-mail Ruling Regarding Motion to Compel Responses (October 8, 2020) (“SDG&E shall not be

required to create a document to respond to [data requests] or present responsive data in a format that does not exist.”).

b. What key factors in SCE’s GNA are driving the overall increase in planned investments across GNA cycles (e.g., from 238 in SCE’s 2021 GNA to 559 in SCE’s 2025 GNA)?

The increase in planned investments is driven by increase in load growth, specifically Transportation Electrification growth, and a change in methodology to accommodate this growth. SCE’s new borrow-forward approach reflects needs in the years they are requested, resulting in a more near-term representation. This contrasts with the previously used “whirlpool method”, which distributed investment needs over a longer time horizon to align with Integrated Energy Policy Report (IEPR). This forced many projects to be delayed, and SCE has recognized that this was an outmoded method given the TE growth that increased starting around 2020. In short, the 2021 GNA was an inadequate representation of needs, and the 2025 GNA is far more aligned with growth on the system.

c. What key factors in SCE’s GNA are driving the increase in number of planned investments in the same year across GNA cycles (e.g., for year 2025, increasing from 5 planned investments in SCE’s 2021 GNA to 143 planned investments in SCE’s 2025 GNA)?

Planned investment increases across the same year is influenced by the GNA reporting structure, which focuses on a five-year planning horizon. Additional investments/projects may be needed but are not approved at the time of filing and are not required to be submitted during this timeframe because they are still too far out in the plan. Additionally, customer applications for load growth are typically submitted when their requirements are more certain, resulting in a clustering of investment needs closer to the execution period.

11. Known Load Deferrals & Cancellations

PAO 5. SCE reports a total known load cancellation rate of 9.8%. Furthermore, SCE reports a known load cancellation rate of 16.14% for the transportation category.

a. What are the reasons SCE or a customer would defer a known load?

Customers may defer known load growth projects for a variety of reasons, including regulatory uncertainty, financial constraints, and project immaturity. SCE works to enable customers to energize on their desired timeline and provides a schedule based on the grid upgrade requirements. If those upgrades extend beyond the customer's preferred date, the customer may choose to defer the project. Additional factors such as paused incentive programs, evolving environmental regulations, limited access to grants or rebates, incomplete planning, permitting delays, and strategic reprioritization due to market conditions or internal goals can also influence deferral decisions.

b. What are the reasons SCE or a customer would cancel a known load?

SCE does not cancel known load projects. Customers may cancel known load growth projects due to a combination of financial, regulatory, execution challenges, and strategic factors. Additionally, complex site conditions, environmental reviews, and multi-party coordination can derail schedules enough to prompt withdrawal. Customers may cancel a load growth project if their business needs change, permitting delays arise, or infrastructure constraints make timely interconnection unfeasible. Cancellations can also result from misalignment between customer timelines and grid readiness, especially when infrastructure upgrades lag behind demand.

It's important to note that cancellation rates reflect project-level attrition rather than a decline in overall sector load forecasts; they simply indicate that some individual requests do not proceed to execution.

c. How often is a known load deferred when a planned investment that addresses that known load is already in-flight?

SCE does not currently track which specific known load directly triggers a planned investment. Instead, we identify whether a planned investment exists on the same circuit as the known load growth project. While deferrals can occur even when investments are in-flight, they are relatively uncommon. Of the 3,342 known load projects reviewed, 1,230 had planned investments on their respective circuit. Among those, only 185 known load projects were deferred, representing approximately 15% of known load projects with planned investments and 5.5% of all known load projects overall.

d. Why is deferral category 3 (both initial and final years of load deferred) much more common than the other deferral categories?

Deferral category 3 (both initial and final years of load were deferred) is more common than other deferral categories primarily due to the way single-year projects are tracked. These projects are recorded with identical start and end years, rather than being distributed across multiple years, and often operate on compressed timelines that make them

particularly susceptible to delays stemming from factors such as customer funding readiness, land negotiations, or dependencies on incentive programs. When such delays occur, the entire load is shifted to a future year, resulting in deferral under category 3. Unlike multi-year projects that allow for partial deferrals, single-year projects either proceed as scheduled or are entirely deferred.

Another key driver of category 3 deferral is the timing and completeness of customer engagement during project development. Delays in customers completing all required information to finalize an application and/or sign contracts can result in the entire project being deferred a year, which shifts both the initial and final years regardless of any planned phasing.

i. Is there any correlation between rate of deferral and size of the load project?

The correlation between load project size and deferral likelihood is not uniform across load types and may be influenced by sector-specific factors such as project complexity, permitting requirements, or customer readiness.

As already noted in response to question 4, for TE projects, deferred loads tend to be smaller compared to non-deferred TE loads. In contrast, for non-TE projects, deferred loads are larger than non-deferred ones. The chart below summarizes the data

	TE		Non-TE	
	Deferred	Non-deferred	Deferred	Non-deferred
Average Size	2.42 MW	3.51 MW	4.23 MW	1.70 MW
Median Size	1.55 MW	1.62 MW	2.25 MW	0.75 MW

Looking at the data overall, there does not seem to be a correlation. Ultimately the best source of information on why some projects are deferred and others are not would come from customers, and would not be shown in a simple data table.

12. Distribution Capital per Customer Metric

PAO 8a. Please provide the distribution capital per customer for 2021, 2022, 2024, and 2025 (or estimate if pending GRC authorization)?

The Distribution Capital per Customer Metric data for the additional years requested is not readily available. The Metric will be developed and incorporated into the Grid Needs Assessment filing as part of the next GRC cycle.

13. General DPAG Comment

ED 1) For future DPAG meetings, Energy Division would prefer to host the meeting platform to allow recordings. The recordings will be used within CPUC and shared elsewhere only with the IOUs approval. ED will also provide the recordings to the IOUs and IPE. Please let us know your thoughts on this.

SCE welcomes the participation by ED to enable recording of these meetings, as well as sharing/posting of this content if approved by participants. In the past, IOUs have hosted these workshops and created recordings, but we do not have a simple method of hosting or sharing the videos outside of our organizations. Any public video on an IOU website requires significant vetting by the IT and potentially public relations teams.