BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

FILED
11/06/26
04:59 PM
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) SUBMISSION OF 2026 INDEPENDENT PROFESSIONAL ENGINEER (IPE) DISTRIBUTION PLANNING ADVISORY GROUP (DPAG) REPORT

WILLIAM YU

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-1634
E-mail: William.W.Yu@sce.com

Dated: **November 6, 2026**

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

Pursuant to the April 20, 2026 Administrative Law Judges' Ruling Setting Schedule for the 2026-2027 Distribution Planning and Execution Process Cycle, Southern California Edison Company ("SCE") respectfully submits its 2026 Independent Professional Engineer ("IPE") Distribution Planning Advisory Group ("DPAG") Report.

Respectfully submitted,

WILLIAM YU

By: William Yu

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-1634
E-mail: William.W.Yu@sce.com

November 6, 2026

Attachment

2026 IPE DPAG Report

resource innovations



Independent Professional Engineer SCE 2026 DPAG Report

PUBLIC VERSION

Submitted to California Public Utilities Commission Energy Division and SCE

November 6, 2026

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 does not contain any 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 DDOR 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 2026 GNA Report 10
      2.2.1. Project Data Used in Load Growth Forecasting 14
      2.2.2. Known Load Tracking Data 28
      2.2.3. Line Segment Needs 32
   2.3. GNA - Observations, Conclusions and Recommendations 32
3. Review of DUPR Report 34
   3.1. DUPR Report Planned Investments - Observations, Conclusions and Recommendations 38
4. Other Items of Interest 39
   4.1. Hot Spots and Developing an Integrated Plan 39
      4.1.1. Hot Spot Methodology and GNA 39
      4.1.2. Developing an Integrated Investment Plan 40
   4.2. Miscellaneous – Observations, Conclusions and Recommendations 45
5. Verification Approach and Results 46
   5.1. PROCESSES TO DEVELOP SYSTEM LEVEL FORECASTS AND DISSAGREGATE TO CIRCUIT LEVEL 47
      5.1.1. Collect 2024 Actual Circuit Loading, Normalize and Adjust for Extreme Weather – Steps 1 and 8 47
      5.1.2. Determine Load and DER Annual Growth on System Level - Step 2 50

5.1.3. Disaggregate Load and DER Annual Growth to the Circuit Level – Step 3 52
5.1.4. Add Load Growth Projects to Circuit Level Forecasts – Step 4 52
5.1.5. Convert Peak Growth to 8760 Profile, Determine Net Load and Peak Load – Steps 5, 6, and 7 53
5.2. PROCESSES TO DETERMINE CIRCUIT NEEDS AND DEVELOP GNA 53
5.2.1. Process to Determine Circuit Needs - Step 9-11 53
5.2.2. Compile GNA Tables Showing Need and Timing – Step 12 53
5.3. PROCESSES TO DEVELOP PLANNED INVESTMENTS AND COSTS 54
5.3.1. Develop Recommended Solution – Step 13 54
5.3.2. Estimate Capital Cost for Candidate Deferral Projects – Step 14 58
5.4. PROCESSES TO DEVELOP CANDIDATE DEFFERAL LIST AND PRIORITIZE 58
5.4.1. Development of Candidate Deferral Projects – Steps 15-17 58
5.4.2. Calculate LNBA Values – Step 18 58
5.4.3. Compare Forecast and Actuals at Circuit Level for 2023 – Step 19 58
5.5. OTHER IPE WORK 61
5.5.1. Review Implementing of Planning Standard and/or Planning Process – Step 22 61
5.5.2. Review List of Internally Approved Capital Projects – Step 23 61
5.5.3. Respond to and Incorporate DPAG Comments – Step 24 62
5.5.4. Track Solicitation Results to Inform Next Cycle – Step 25 62
5.5.5. Treating confidential material in the IPE Report – Step 26 62
5.5.6. Project Prioritization - Step 27 63
5.5.7. Project Execution Tracking Data and Metrics – Step 28 63
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 for 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)5 was filed to replace the 2014 Distribution Resource Plan and now stands as the OIR home for GNA and DDOR 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.

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 that portions of the DIDF process be suspended temporarily and removing solicitation-related reporting requirements within the 2024 GNA/DDOR reporting period, as well as off-ramping the Partnership Pilot.

In October 2024, Decision 24-10-030 eliminated the DIDF solicitations process. The decision focused on measures to enhance the transparency of the distribution planning process. This included renaming DDOR to Distribution Upgrade Project Report (DUPR) and additional reporting requirements in the DUPR.

In December 2025, the Commission adopted Resolution E-5413 (Pending Loads) and Resolution E-5414 (Scenario Planning), which establish additional requirements applicable to the 2025–2026 Distribution Planning and Execution Process (DPEP) cycle and this GNA/DUPR filing.

Resolution E-5413 requires utilities to implement a standardized pending loads framework, including the categorization, tracking, and reporting of pending loads in the GNA and DUPR, and to describe how changes in pending load assumptions are incorporated into grid need identification and planned investments.

Resolution E-5414 requires utilities to adopt a scenario planning framework based on Low, Base, and High load growth scenarios and to incorporate the results of those scenarios into both the GNA and DUPR. The Resolution further requires utilities to develop and report a transparent decision logic framework describing how multiple scenario outcomes are translated into a single set of planned investments included in the DUPR.

In April 2026, the ALJ issued a ruling that set the schedule for the 2025-26 and 2026-27 Distribution Planning and Execution Process (DPEP) cycles. The schedule for the 2025-26 DPEP cycle is shown in Table 1-1.

Table 1-1: Proposed DPAG Schedule for 2025-26 DPEP Cycle (Partial table from the April 2026 ALJ Ruling)

Activity	Date
IOU GNA/DUPR filings Final IPE Plans Circulated	August 17, 2026
IPE Preliminary Analysis of GNA/DUPR data adequacy circulated	September 4, 2026
DPAG meetings with each IOU	Week of September 14, 2026
Participants provide questions and comments to IOUs and IPE	September 25, 2026
IOU responses to questions	October 5, 2026
Follow-up IOU meetings via webinar (Optional)	Week of October 12, 2026
IPE DPAG Reports	November 6, 2026
IPE Post-DPAG Report (covering all three Utilities)	March 15, 2027

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). Through a contract with Resource Innovations, SCE engaged Mr. Sundar Venkataraman[1], PE, to serve as the advisory engineer (referred to as the Independent Professional Engineer (IPE)).

The Independent Professional Engineer (IPE) services for the 2025-26 Distribution Planning and Execution Process (DPEP) 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. 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

[1] Consistent with the CPUC decision, the contract with Resource Innovations (RI) provides for other individuals within RI to assist Mr. 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.

modifies the original scope and includes additional scope items to support the High DER proceeding. This updated scope of work is included as Appendix A.

1.1. IPE Plan

As required by the April 23, 2020 Ruling, the IPE developed an IPE Plan that guided the IPE's steps to verify and validate the GNA/DDOR results. The plan was developed using a three-step process:

1. In Step 1, IPE developed a draft IPE Plan working with the Energy Division and SCE by mid-May 2026.
2. The Plan was distributed to the service list and 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 17, 2026.

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

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, to using the CEC IEPR forecasts to develop utility specific system level values which are then disaggregated to the circuit level, then 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.

In every DPEP 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 in the IPE's scope. Based on this review, the following steps were skipped since the business process used by the utility did not change from 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.

In addition, the verification and validation of the following steps related to the identification and prioritization of Candidate Deferral Opportunities (CDOs) are no longer required since the requirement for DIDF solicitations have been eliminated as per the October 2024 Decision.

- 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
- Step 25 - Track solicitation results to inform next cycle.

In addition, based on input from the ED, the following steps were also 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.

Two steps (Steps 27 and 28) were added in the last cycle. Step 27 will be skipped in this cycle since there has not been any substantial change in the process. Step 28 will be included in this cycle.

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

Several new steps were added in this cycle as summarized below.

- Step 4b – Determine hot spots
- Step 4c - Gather Pending Loads data used in Step 2
- Step 13b - Develop solution for single investment plan
- Step 13c - Determine if planned solutions/projects identified in previous cycles continue to be needed and are the appropriate solution to meet the need (project scope and timing)
- Step 20b - Analyze pending load tracking dataset. Review categorization of PL and supporting information

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 – 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 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?"

1.3. Services Considered within the DDOR Framework

The CPUC, in a previous decision, approved the four services proposed by the Competitive Solicitation Framework Working Group (CSFWG) and directed the utilities to consider these services in the GNA/DDOR process. The four services, as 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 circuit 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 services capable of improving local distribution reliability and/or resiliency. Specifically, this service provides 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 2026 Distribution Forecasting Working Group held on May 19, 2026
- 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 25 – Steps 2 and 5
  - July 17 - Steps 3 and 4
  - August 7 – Steps 1 and 8
  - September 8 – Steps 19 and 20
  - October 16 – Step 12, 13 and 28
- 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 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 for the integrated plan and the difference between SCE and other IOUs because of its Subtransmission System and any significant differences noted in SCE's reports between the 2026 and 2025 DIDF cycle. This section will also include discussion of known load and pending load 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 for the integrated plan, and any significant differences noted, if any, in SCE's reports between the 2026 and 2025 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 including hot spots and decision logic. 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, 2026, 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 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 2026 GNA Report

SCE's GNA Report is a written report narrative along with three tabs in a combined GNA and DUPR Excel database which includes potential grid needs on its distribution and subtransmission system under CPUC jurisdiction. SCE filed its GNA and DUPR Report on August 15, 2026. In this report we only touch upon a few highlights of the report and Excel spreadsheet tabs in the GNA Report and recommend to those who are interested in more details to review the GNA Report narrative and associated spreadsheets.

In this cycle, SCE made the following changes to the GNA/DUPR reports compared to the corresponding reports in the previous cycle:

- Implemented the CPUC decision on applying IEPR Caps (Decision R.21-06-017 OP1 and OP2)
- Implemented the CPUC's resolution on pending loads (Resolution E-5413))
- Implemented the CPUC's resolution on scenario planning (Resolution E-5414)
- Implemented decision logic to develop a single integrated investment plan
- Change to an element level load allocation (double counting mitigation)
- Enhanced representative load shapes

As a result of all these decisions/resolutions and changes, SCE developed four GNA reports, one for each of the three scenarios defined in the scenario planning resolution, and a fourth that SCE referred to as a Synthesized report that integrated the results of the three scenarios. SCE also developed four DUPR reports as discussed in the following sections. This section discusses the GNA report for only the Synthesis Scenario results unless otherwise noted.

The GNA includes forecasted equipment deficiencies, incremental demand, and incremental DER growth for each circuit and distribution substation with a grid need over a five-year forecast horizon. Three worksheets are included within the GNA report:

- Grid Needs Assessment (GNA)
- Planning Assumptions_Feeder
- Planning Assumptions_DistSub

The “Planning Assumptions_Feeder” worksheet and the “Planning Assumptions_DistSub” worksheet contain a 10-year load and DER forecast for SCE’s distribution circuits and distribution substations. The "Facility Loading Limit" column represents the MW value at which the representative facility can be safely operated to serve load for the specified year of the forecast. The "Total DER Growth" column for the feeder worksheet is a summation of DER growth for the feeder for the specified year of the forecast. These include the DERs reported within the feeder-level planning assumptions sheet. As a point of clarification, the EV DER column is a summation of all TE categories as covered within Table 15 of SCE’s GNA/DUPT report. Similarly, the "Total DER Growth" column for the substation worksheet is a summation of DER growth for all downstream circuits of the representative facility for the specified year of the forecast. These include the DERs reported within the distribution substation-level planning assumptions sheet.

In the “Grid Needs Assessment (GNA)” sheet, the "Equipment Rating" column for a facility is the absolute minimum rating over the ten years for the corresponding asset. When a single facility has multiple projects developed and presented in the DUPR (e.g., due to a different timeframe of the needs), the lowest rating over the ten years is utilized. In addition, when a single asset has multiple projects included in the DUPR, the operating date for this asset presented in the “Grid Needs Assessment (GNA)” sheet is the earliest operating date of the corresponding project in the DUPR.

The 2026 GNA for the Synthesis Case covers needs for all distribution circuits and substations and subtransmission lines and substations under the jurisdiction of the CPUC, including 1885 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 2026. For easy reference a few of these tables are duplicated here along with similar tables from SCE’s 2025 GNA. Note the tables with 2026 values are from the fourth GNA referred to as the Synthesis Case GNA results.

Table 2-1: GNA Needs by Asset Type from 2025 GNA and 2026 GNA

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**

2026 GNA Total Needs by Asset Type

Asset Type	Capacity	Capacity (UCT)	Reactive Power	Reliability, Capacity	Reliability, Voltage	Voltage	None	Total
Distribution Feeder	523	658	36	5	0	12	177	**1,411**
Distribution Substation	153	10	13	30	16	11	38	**271**
Subtrans. Substation	4	7	0	0	0	1	0	**12**
Subtransmission Line	59	17	0	111	1	0	3	**191**

Table 2-2: Summary of Grid Needs by Distribution Service Type and Region from 2025 and 2026 GNA

2025 GNA Total Needs by Type and Region

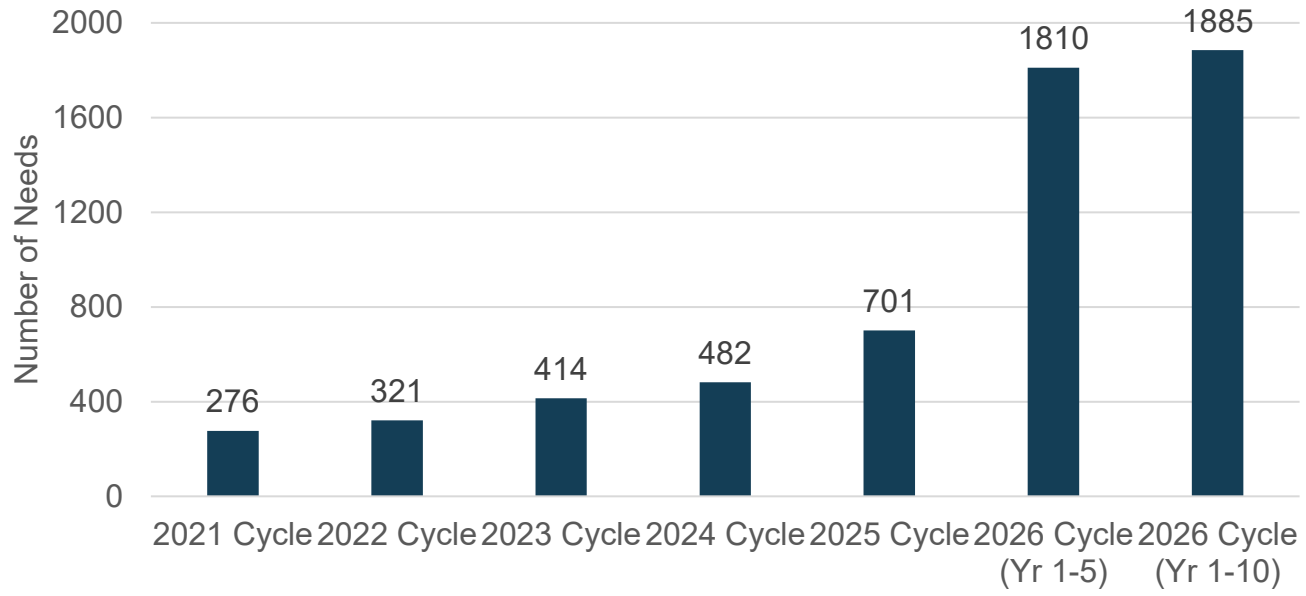
Region	Capacity	Capacity (UCT)	Reactive Power	Reliability, Capacity	Reliability, Voltage	Voltage	Total
Desert	34	80	6	10	0	5	135
Metro East	45	77	13	16	0	4	155
Metro West	74	16	7	3	0	0	100
North Coast	4	20	5	2	1	0	32
North Valley	21	18	5	6	1	1	52
Orange	13	70	9	3	0	0	95
Rurals	17	21	10	2	0	2	52
San Jacinto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

2026 GNA Total Needs by Type and Region

Region	Capacity	Capacity (UCT)	Reactive Power	Reliability, Capacity	Reliability, Voltage	Voltage	None	Total
Desert	128	147	12	31	5	8	41	**372**
Metro East	149	115	4	26	0	2	13	**309**
Metro West	139	63	9	10	0	0	22	**243**
North Coast	22	26	3	8	2	0	16	**77**
North Valley	55	38	3	17	2	3	23	**141**
Orange	77	142	5	14	0	0	66	**304**
Rurals	66	53	4	3	1	7	11	**145**
San Jacinto	64	74	4	13	1	0	13	**169**
San Joaquin	32	33	1	12	0	3	10	**91**
Unassigned	7	1	4	12	6	1	3	**34**
Total	**739**	**693**	**49**	**146**	**17**	**24**	**218**	**1,885**

In Figure 2-1 below the total GNA needs in the Synthesis case are plotted for the last six cycles. Analyzing this data indicates that the number of needs shows steady growth over those six cycles that totals over 680% growth and a growth of 270% over last two cycles. We note that the plot shows that in this cycle 1810 out of the total of 1885 (or 96%) of the needs are in the first five years of the planning 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 known loads 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, 8) if not, develop a project that will resolve the overload and application of decision logic The verification of some 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:

- Known Load data
- Incremental Known Load project data
- Pending Load Data – Categories A, B1, B2 and C
- IEPR Base Load Consumption Forecast data
- IEPR Light Duty Away from Home Forecast data
- IEPR MDHD Forecast data
- IEPR Bus Forecast data
- IEPR Building Electrification data
- 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. Below we review some of the load forecast components listed above.

Known Loads

Known loads are again used in the forecasting process. The count and MVA of known loads used are shown in the two tables below. We see from the tables that known loads are heavily front loaded in the first few years and tail off after 5 years. The total count and amount of known loads over the planning period were a count of 2484 and an amount of 3884 MVA respectively.

Table 2-3: Count and MVA of All Known Loads

Count and MVA of All Known Loads

Forecast Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Count of Known Loads	1760	450	137	60	34	19	9	6	4	3

MVA of All Known Loads

Forecast Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Sum of Load Amount	2394.8	788.6	289.3	115.1	63	26	30.4	23.6	22.5	129.7

Incremental Known Load Growth Projects

SCE utilized incremental load growth projects in the 2026 DIDF cycle as it has done in the recent past to develop its forecasts at the circuit level with several changes to what was used in 2025. In 2026 the following types of Incremental KLs were included in the load forecast – Temporary Power, Load WDAT, Customer Substations and Firm Charging which were also included in 2025. The following types of KLs were included in 2025 but were not included in 2026 – Cultivation, Commercial EV Chargers, EV Vendor Forecasts, Port Shore Power, Port MDHD, TSE.

All the 2026 incremental known loads which are considered by SCE not to be included in the IEPR load growth forecast are treated as additive to the IEPR forecast. With the removal of cultivation and commercial EV chargers which were by far the largest incremental known loads historically and the other loads used in 2025 and not in 2026, there are significantly fewer incremental known loads in 2026 (22 MW) compared to 2025 and thus they have very limited impact on the planning process in this cycle.

Pending Load

To support integration into the planning process, SCE indicated that it feeds its proposed pending loads into the minimum criteria framework to assign the proper categorization

based on expected timing, magnitude, and geographic location certainty. Once these loads are under their respective category (A, B1, B2 or C), additional guardrails (i.e. hot spots and IEPR caps) get applied to further mitigate the certainty level of these loads materializing.

SCE's Pending load reporting, per CPUC resolution, is designed to provide visibility into the underlying data sources and assumptions used in planning while remaining consistent with the overall structure of the GNA and DUPR datasets.

Pending Load categories and minimum criteria were formally established in December 2025. As a result, SCE's pending load data from prior forecasting cycles is not directly comparable to the current planning year due to the introduction of a standardized framework. Accordingly, metrics that compare current Plan Year Pending Load data with prior Plan Year results are not included in this report.

As part of this process, SCE indicated that it incorporated targeted bottom-up analyses to capture emerging load growth that may not be reflected through traditional forecasting approaches. These efforts include transportation electrification analyses, including truck stop infrastructure assessments from the West Coast Clean Transit Corridor Initiative and medium- and heavy-duty vehicle electrification forecasts developed using Guidehouse's Transportation Electrification Proactive Planning (TEPP) Framework. Additionally, SCE incorporated port-related electrification initiatives and identification of residential and commercial development projects associated with permitting activity (i.e., California Environmental Quality Act (CEQA) database). SCE indicated B2 growth was informed by the Final Report: Interstate 5 Corridor California, Oregon, Washington, from the West Coat Clean Transit Corridor Initiative and Guidehouse's Transportation Electrification Proactive Planning Framework. These were briefly covered in Section 6.1 of the GNA/DUPR narrative.

Pending Load data is shown in several tables that follow. The following can be observed from those tables:

- In Table 2-4 we see that the sum of the MVA for Type A and B1 (which are both about 2,300 MVA) far exceed the sum of the MVA for Type B2 and C which each total around 350 to 400 MVA. We also see in that table that the Type A and B1 PLs tend to be more front loaded than the B2 and C Pending Loads.
- In Table 2-5 we see that the sum of the Commercial MVA for Type A PL is the largest type and substantially larger than Transportation; we see that Transportation is more front loaded than Commercial Pending Loads.
- In Table 2-5 we see that the sum of the Transportation MVA for Type B1 is by far the largest type with the largest category being the LD EV.
- In Table 2-5 we see that Transportation MVA is the only B2 PL, and that load is rather small and it is relatively flat over the planning period.

- In Table 2-5 we see that Transportation is somewhat larger than the other types and has a small peak in year 5 and trails off after that. We see that the remainder of the PLs begin in year 7 and are relatively small.
- Overall, Type A and B1 dominate the number and amount of Pending Loads in this cycle; A PLs are included in all three scenario forecasts and can exceed the IEPR; B1 PLs are included in the Base Case and the High Case and can exceed the IEPR in both instances; B2 PLs are included in the High Case and the Base Case if located in a Hot Spot and can exceed the IEPR; C PLs are included in the High Case and can exceed the IEPR if in a Hot Spot.
- Overall, the B2 and C PLs which exceed the IEPR because they are in a Hot Spot are relatively small.

Table 2-4: Pending Load Growth Count and MVA Over the Years

Pending Loads – Count for All Categories

Forecast Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Count of Pending Load (Cat. A)	415	281	137	74	48	24	16	11	7	1
Count of Pending Load (Cat. B1)	0	342	198	572	406	341	323	56	65	15
Count of Pending Load (Cat. B2)	0	13	13	22	19	18	18	16	17	17
Count of Pending Load (Cat. C)	0	0	0	0	51	0	156	197	180	180

Pending Loads – MVA for All Categories

Forecast Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Sum of Load Amount (Cat. A)	812.4	663.5	319.0	203.1	129.5	66.9	62.4	26.0	16.6	5.3
Sum of Load Amount (Cat. B1)	0.0	853.4	343.1	451.4	199.7	149.8	134.9	55.0	55.0	27.1
Sum of Load Amount (Cat. B2)	0.0	73.4	33.5	34.7	42.0	62.2	44.6	18.0	16.9	18.1
Sum of Load Amount (Cat. C)	0.0	0.0	0.0	0.0	124.8	0.0	2.6	118.2	103.1	44.2

Table 2-5:Pending Load Growth MVA by Type and Category

Pending Load Growth Type A MVA by Type and Category

Forecast Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Agriculture	1.3	0.2	0	0	0	0	0	0	0	0
Commercial	258.6	327.8	122.1	83.0	48.7	38.0	15.4	9.1	0.7	0
Education	3.9	9.2	-0.6	0	0	0	0	0	0	0
Health Care	10.3	9.2	-0.6	0	0	0	0	0	0	0
Business	128.0	183.0	58.2	26.0	13.7	9.0	0	0	0	0
Other	116.3	87.0	54.4	51.3	30.7	28.8	15.1	6.8	0	0
Industrial	55.0	87.8	67.2	49.9	15.3	1.5	0	6.0	5.0	0
Plants	18.0	26.6	22.1	5.0	2.5	1.5	0	1.0	0	0
Facilities	0.8	19.8	0	0	0	0	0	0	0	0
Cultivation	34.3	41.4	45.0	44.9	12.8	0	0	5.0	5.0	0
Other	2.0	0	0	0	0	0	0	0	0	0
Residential	52.0	126.8	100.6	65.1	62.9	27.4	22.0	10.9	10.9	5.3
Home Construction	46.8	102.1	88.6	59.6	58.9	22.8	18.3	9.5	10.8	5.3
Other	5.2	24.7	12.0	5.5	4.1	4.6	3.7	1.4	0.1	0
Transportation	445.5	120.9	29.1	5.2	2.5	0	25.0	0	0	0
LD EV	257.5	38.0	3.0	5.2	0	0	0.0	0	0	0
MD/HD EV	188.1	82.9	26.1	0	2.5	0	25.0	0	0	0

Pending Load Type B1 MVA by Type and Category

Forecast Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Agriculture	0	1.0	2.0	3.0	4.0	5.0	6.0	7.0	8.0	9.0
Commercial	0	0	0	62.3	62.3	23.7	19.2	8.3	8.3	5.6
Education	0	0	0	8.4	8.4	5.1	3.0	0	0	0
Health Care	0	0	0	4.4	4.4	2.4	0	0	0	0
Business	0	0	0	35.3	35.3	11.1	11.1	8.3	8.3	5.6
Other	0	0	0	14.1	14.1	5.1	5.1	0	0	0
Industrial	0	0	17.5	31.5	38.5	16.1	14.1	8.4	5.6	5.6
Plants	0	0	0	0	0	0	0	0	0	0
Facilities	0	0	0	0	0	0	0	0	0	0
Cultivation	0	0	0	31.5	31.5	16.1	14.1	8.4	5.6	5.6
Other	0	0	17.5	0	7.0	0	0	0	0	0
Residential	0	0	0	96.7	96.7	96.7	96.7	19.6	16.2	14.5
Home Construction	0	0	0	96.7	96.7	96.7	96.7	19.6	16.2	14.5
Other	0	1.0	2.0	3.0	4.0	5.0	6.0	7.0	8.0	9.0
Transportation	0	853.4	325.6	260.9	2.3	13.2	4.9	18.6	24.8	1.4
LD EV	0	756.9	249.0	258.3	2.3	13.2	4.9	7.6	24.8	1.4
MD/HD EV	0	96.6	76.6	2.6	0	0	0	11.0	0	0

Pending Load Type B2 MVA by Type and Category B2

Forecast Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Agriculture	0	0	0	0	0	0	0	0	0	0
Commercial	0	0	0	0	0	0	0	0	0	0
Education	0	0	0	0	0	0	0	0	0	0
Health Care	0	0	0	0	0	0	0	0	0	0
Business	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
Industrial	0	0	0	0	0	0	0	0	0	0
Plants	0	0	0	0	0	0	0	0	0	0
Facilities	0	0	0	0	0	0	0	0	0	0
Cultivation	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
Residential	0	0	0	0	0	0	0	0	0	0
Home Construction	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
Transportation	0	73.4	33.5	34.7	42.0	62.2	44.6	18.0	16.9	18.1
LD EV	0	0	0	0	0	0	0	0	0	0
MD/HD EV	0	73.4	33.5	34.7	42.0	62.2	44.6	18.0	16.9	18.1

Pending Load Type C MVA by Type and Category

Forecast Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Agriculture	0	0	0	0	0	0	0	0	0	0
Commercial	0	0	0	0	0	0	0.9	27.1	36.5	14.7
Education	0	0	0	0	0	0	0	0	0	0
Health Care	0	0	0	0	0	0	0	0.9	1.6	0.6
Business	0	0	0	0	0	0	0.7	21.0	28.3	11.4
Other	0	0	0	0	0	0	0.2	5.1	6.6	2.7
Industrial	0	0	0	0	0	0	0.2	4.4	10.1	3.7
Plants	0	0	0	0	0	0	0.2	3.6	8.6	3.1
Facilities	0	0	0	0	0	0	0	0	0	0
Cultivation	0	0	0	0	0	0	0	0.7	1.5	0.5
Other	0	0	0	0	0	0	0	0	0	0
Residential	0	0	0	0	0	0	1.0	35.1	56.2	25.7
Home Construction	0	0	0	0	0	0	0.9	33.0	53.8	24.8
Other	0	0	0	0	0	0	0.1	2.1	2.4	0.9
Transportation	0	0	0	0	124.8	0	0.5	51.7	0.3	0.1
LD EV	0	0	0	0	124.8	0	0	0	0	0
MD/HD EV	0	0	0	0	0	0	0.5	51.7	0.3	0.1

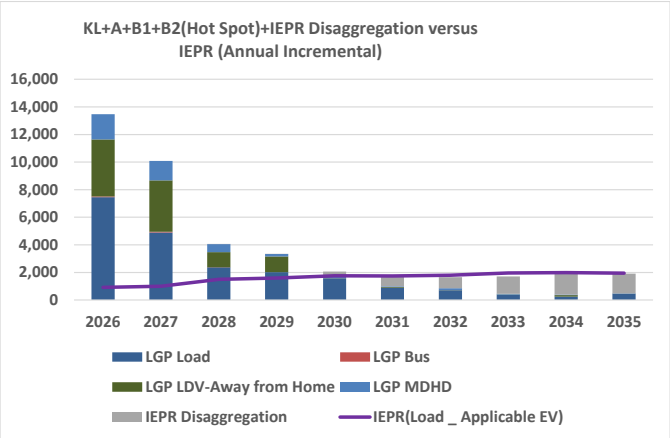
Net Load Forecast

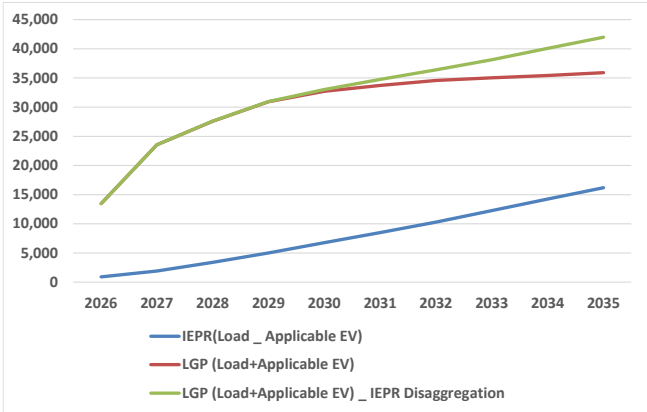
Shown in Figure 2-2 is a plot that demonstrates how Known and Pending Loads and IEPR Disaggregation load growth impacted the ultimate load forecast in the Base Case. The graph on the left plots the Known and capped Pending Load and IEPR Disaggregation Load growth in GWh included in Base Scenario with values discounted for diversity. The left plot includes a bar chart of the load growth components that resulted from the application of IEPR caps. The left plot also includes a solid line showing the corresponding total IEPR load growth value. The left plot also includes IEPR Disaggregated Load (Econometric Load) shown as a grey bar starting in year 2031 that resulted from the application of the IEPR caping methodology. We

see that the annual total of the bar charts on the left are much larger than the corresponding IEPR value for the first four years of the planning process with Known Loads and LDEV Away from Home dominating growth in these four years.

The plot on the right contains cumulative values for the Bar charts for the IEPR load growth (blue line), the Known and Pending Load growth (red line) and the Known and Pending Load growth plus econometric load growth (green line). We see on the right chart that on a cumulative basis the total load growth in GWh exceeded the IEPR value over ten years by more than two and a half times.

Figure 2-2: Known, Pending and IEPR Load Growth - Annual and Cumulative Values





Econometric Load Growth

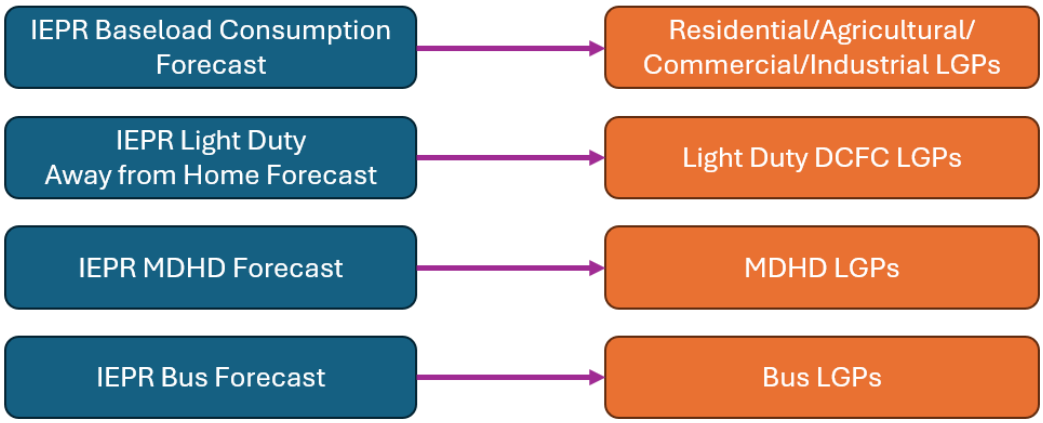
This system level load component is developed as one of the results of applying the IEPR cap methodology. This load is disaggregated to the circuit level using an appropriate adoption propensity methodology. As we saw earlier, there is some econometric load growth in this cycle in the Low, Base and High cases.

Applying IEPR Caps Overall

In this section we review how SCE applied the IEPR caps in the development of its total growth forecast. In Figure 2-3 below we see four components of the SCE load forecast that are subject to the application of IEPR caps. The IEPR caps for these areas are applied independently from each other by comparing the annual IEPR values against the load growth values.

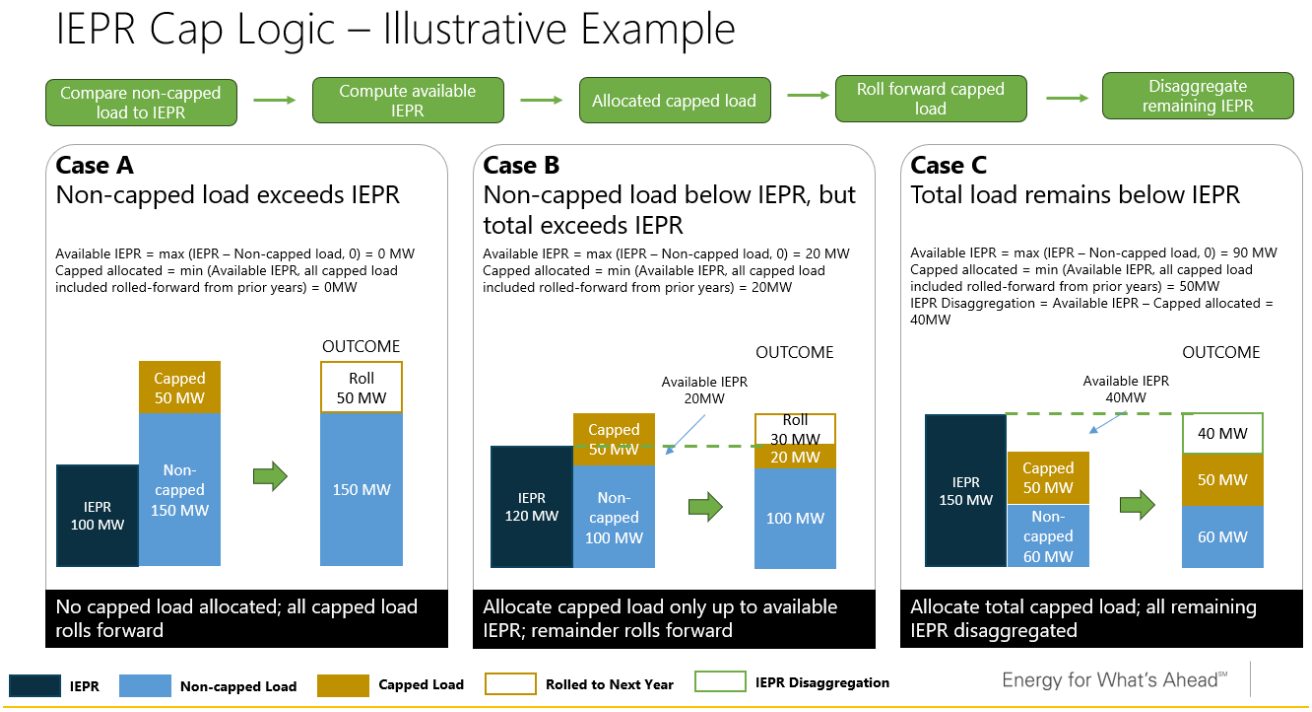
Figure 2-3: Four IEPR Elements and Associated Load Growth Projects

- Match relevant IEPR forecast elements with their associated LGPs (known and eligible pending categories) to determine if uncapped LGPs exceed the IEPR forecast.



In Figure 2-4 below provided by SCE, we see a graphic summary of the IEPR cap process SCE used on these four load growth components.

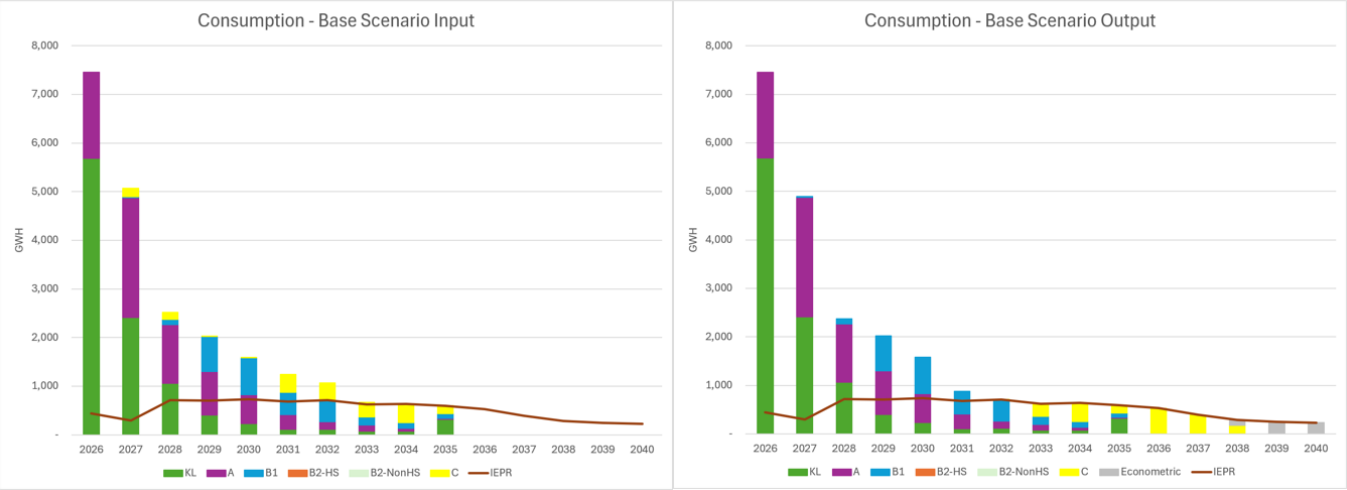
Figure 2-4: Overview of IEPR Cap Process



IEPR Cap - Consumption Forecast

Shown in Figure 2-5 below, we see results of the application of IEPR caps on the Consumption element of the IEPR forecast. In the left chart we see all the inputs to the cap methodology for the base Case including Known Loads, Pending Loads A, B1, B2 in Hot spots, B2 not in a hot spot and C and a red line for the corresponding IEPR annual values. In the right chart we see the result of applying the IEPR cap which shows that KLs and Pls A and B1 and B2 in a hot spot are not limited by the cap process and that B2 and C are limited and do not exceed the IEPR and are rolled over to future years where they are used to disaggregate IEPR load in the later years of the 15-year forecasting period.

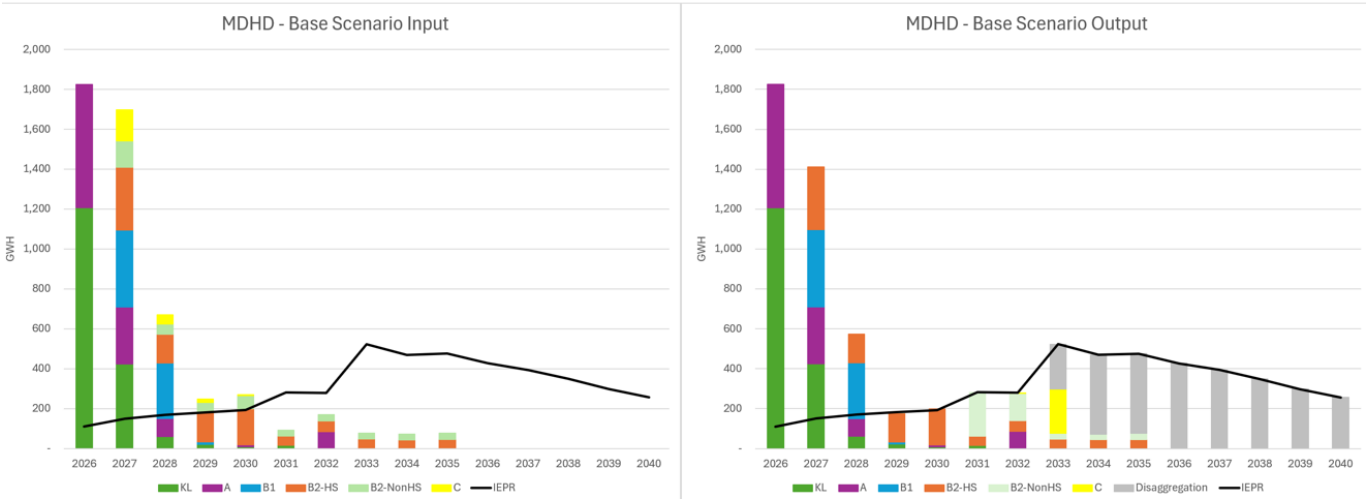
Figure 2-5: Consumption Forecast with IEPR Caps – Base Case



IEPR Caps – MDHD EVs

Another example is the application of IEPR caps to MDHD EVs in the Base Case that is shown in Figure 2-6 below. We see that again KLs, PLs A, B1 and B2 in hot spots are not impacted by the caps but B2 loads not in a hot spot and C PLs are impacted. They are rolled over into future years and in this case, we see that there is a substantial amount of econometric load added in the later years as a result of applying the IEPR Cap methodology.

Figure 2-6: MDHD EVs with IEPR Caps – Base Case



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 and grows 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.

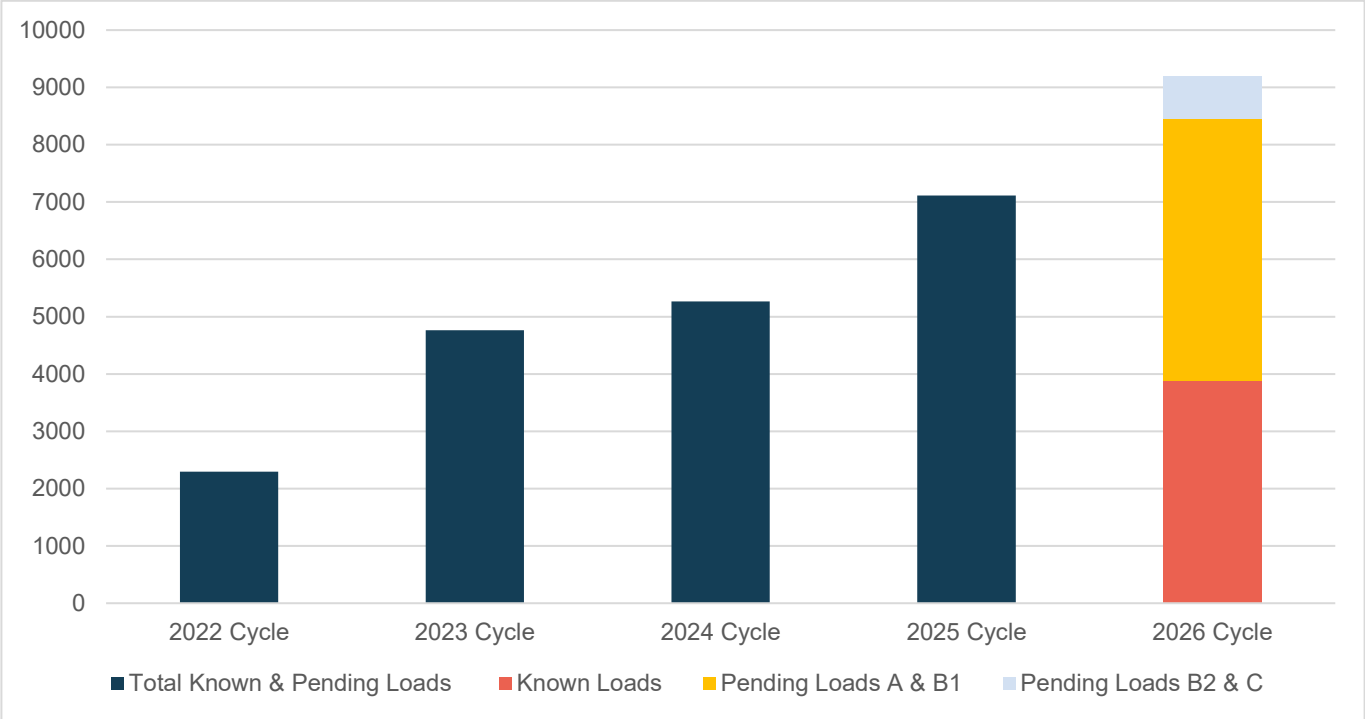
PV Generation – SCE incorporates PV production in its net load growth estimates which results in a decrease of load. These estimates are driven by the IEPR.

Known and Pending Load Growth

Figure 2-7 below shows the sum of known loads plus pending loads, which include all types of loads including EVs. In this figure, the sum of known and pending loads are shown for the 2022-2026 cycles. For the 2026 cycle, the known loads and pending loads are shown separately. We see that the sum of known and pending loads has increased over time – about 400% over that five-year period. We see that this sum has increased in 2026 compared to 2025 by 29% if one considers all Pending Loads and by 19% if one includes only the more certain A and B1 Pending loads in 2026. We also see in Table 2-7 later in this report that there

has been a substantial decrease in total number and MVA of Known Loads in 2026 compared to 2025.

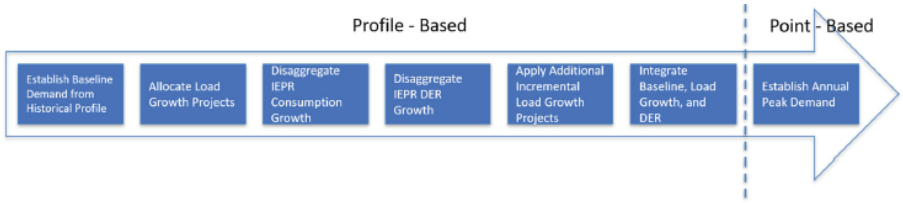
Figure 2-7: Known and Pending Load Growth



SCE Overall Disaggregation Process

Shown in Figure 2-8 below is the overall process SCE uses to develop Load Forecasts. SCE provided a detailed summary with examples of the steps used to develop distribution load forecasts so we will not duplicate this material instead will touch upon key aspects of the process.

Figure 2-8: End to End Distribution Load Forecasting Process



1. *Establish Baseline Demand from Historical Profile*:
   Baseline demand profiles for distribution structures are developed using regression based on cleansed 8760 historical profiles and are adjusted to reflect an average (1-in-2) temperature assumption.

2. *Allocate Load Growth Projects:*
   LGPs are allocated to distribution structures based on their classification (e.g., known loads and pending load categories) and incorporated according to the CPUC's scenario planning framework and IEPR cap and hot spot logic.

3. *Disaggregate IEPR Consumption Growth*:
   The remaining IEPR consumption forecast is disaggregated to the distribution structure level using econometric models, incorporating demographic, economic, and land-use drivers not captured through LGPs.

4. *Disaggregate IEPR DER Growth*:
   IEPR DER forecasts are disaggregated to the circuit level using a common disaggregation framework. Where applicable, portions of the IEPR DER forecast associated with LGPs (e.g., certain transportation electrification segments) are first accounted for through the LGP allocation process in Step 2; the remaining forecast is then disaggregated using analytical methods.

5. *Apply Additional Incremental Load Growth Projects*:
   Limited incremental LGPs not captured in Step 2 are incorporated into the forecast after IEPR load and DER disaggregation. These projects represent incremental adjustments that IEPR forecast doesn't account for, which helps to ensure the forecast reflects the planning needs.

6. *Integrate Baseline, Load Growth, and DER*:
   Baseline demand, allocated LGPs, disaggregated IEPR consumption and DER forecasts are combined. Hourly profiles are applied to develop an initial 8760-hour net demand forecast for each circuit. The resulting forecast reflects total demand, including both baseline conditions and growth. Profiles used include DER-specific shapes and representative sector load shapes (e.g., residential, commercial, industrial, agriculture, and transportation electrification).

7. *Establish Annual Peak Demand*:
   Circuit peak demand is identified from the integrated hourly net demand forecast, and coincident load and DER impacts are determined based on the circuit peak hour.

Double Counting

SCE indicated that their new approach which includes allocating load at the element-level addressed one of the areas with the potential for double counting. This approach:

- Allocates and processes load growth by forecast element
- Adjusts IEPR base energy and DER forecasts by year and element to reflect allocated load and load-increasing DER, preventing double counting.
- Separates LDV Home and Away Charging in the IEPR cap process and uses different shapes for each

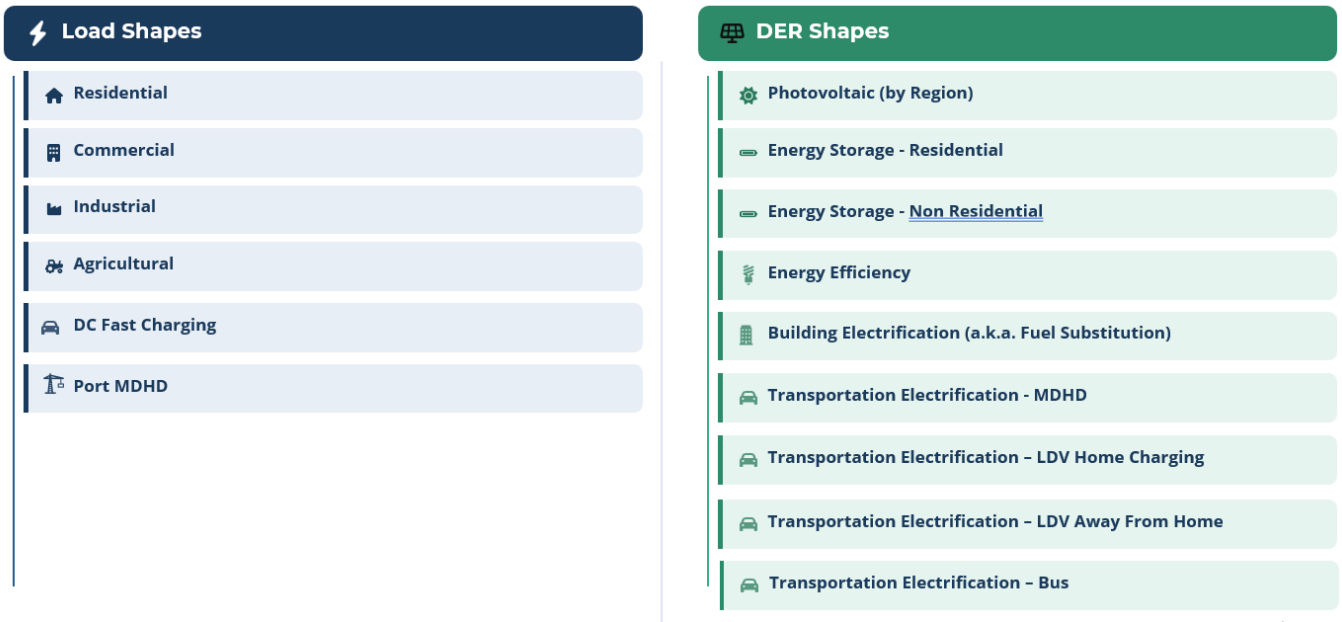
DER and EV Shapes and Profiles

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 basically the same as those used in the previous cycle, however some improvements have been made in this cycle.

Figure 2-9 below depicts the overall approach SCE used in applying shapes in the DPP process for this cycle.

Figure 2-9: Load Shapes Used in 2026



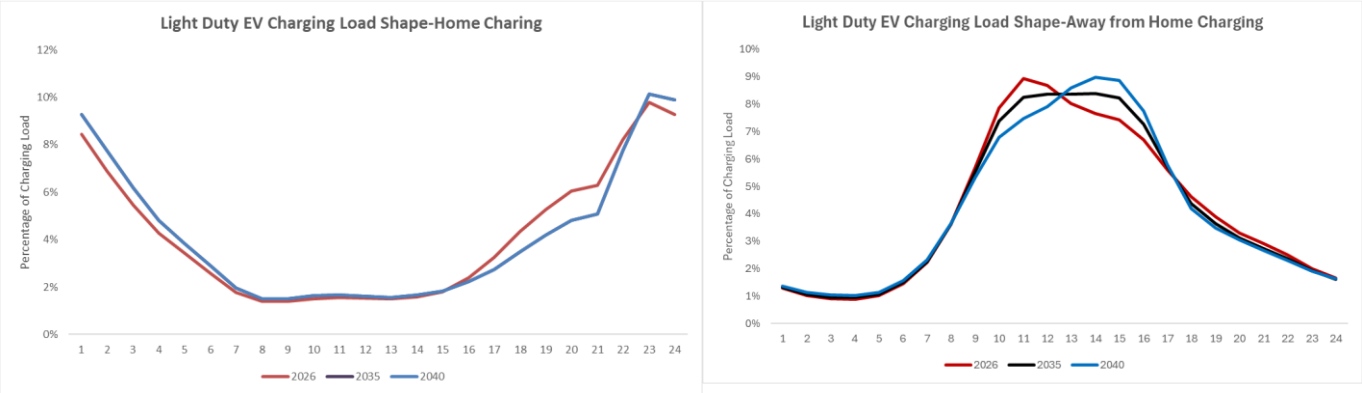
SCE made some improvements in the shapes that they used in this cycle as summarized in Table 2-6 below.

Table 2-6: Methodology Changes in 2026

Category	Prior Approach (PY25)	Updated Approach (PY26)	Key Improvements
Data Treatment	Gross load: Net + PV	Net load derived from non-PV customer segment to avoid embedded generation bias	Reduced reliance on PV assumptions
Shape Development	Aggregate-based normalization: - *Sum hourly meter reads and normalize*	Customer-level normalization followed by aggregation: - *Normalize individual customer load profiles* - *Aggregate into representative shape*	Better representation of usage patterns
Time Alignment	Calendar-based alignment	Pattern-based alignment (e.g., day-of-week, holiday adjustments)	More realistic temporal profiles
Shape Application	Static annual shape averaged from limited historical shapes	Static annual shape derived from expanded years of distinct shapes in the planning horizon	Reduced bias from limited data

This enhanced methodology allowed the splitting of the Light Duty EV load shape into Home and Away-from-Home charging to better capture distinct behavioral patterns across customer segments. The home charging shape is a weighted aggregation of Domestic and TOU customer charging behaviors. The away-from-home charging shape is a weighted aggregation of workplace Level 2 and DCFC charging behavior. Those two shapes are shown below in Figure 2-10.

Figure 2-10: Home and Away from Home Light Duty Charging



For medium- and heavy-duty vehicles, the CEC's 2024 IEPR MDHD shape is used and for buses, Guidehouse's work from the CPUC's Transportation Electrification Proactive Planning proceeding is applied.

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 some types of charging due to the incentives built into rates to avoid charging during peak periods.

In our previous review we found one shape (IEPR LDV Charging) that seemed to indicate that noticeable charging would occur during the peak period. In this cycle, as one can observe in the figure above, home charging captures the impact of incentives in that we see a negligible amount of charging in the typical TOU Peak Rate period (approximately 4PM to 9PM).

2.2.2. Known Load Tracking Data

This section in SCE's GNA shows how SCE is addressing Reform 2.6 from the 2022 DIDF 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. Note some revisions to the reporting have been made by the ED since the March 17, 2022 IPE Report.

To address this requirement SCE's GNA included, for the fourth 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 date[2]. Known load data were included in SCE's 2022, 2023, 2024 and 2025 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 one of the dominant factors 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 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 2026 GNA/DUPR filing includes the following information - the impacted circuit, unique project identifier, load type, load category, status, requested load amount, initial service request date, current expected in-service date, status, actual in-service date, and actual load amount among other data.

[2] 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.

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 (Attribute/Field Brief Description):

- Unique Modifier / Unique identifier for each known load.
- Distribution Substation Name / Name of the distribution substation that would serve the known load.
- Distribution Substation ID / ID of the distribution substation that would serve the known load.
- Substation Bus / Bus ID that would serve the known load.
- Distribution Circuit Name / Name of the circuit serving the known load.
- Distribution Circuit ID I/ D of the circuit serving the known load.
- Load Type Load type classification. / Categories include Agriculture, Commercial, Residential, Industrial,
- Transportation, or Energy Storage. / SCE currently does not have any Known Load Projects classified under the Energy Storage load type.
- Load Category / Subcategory of the load type.
- Expected Load Amount (MVA) / Expected load amount associated with the known load request. This value does not reflect any adjustments applied through SCE's load forecast process.
- Initial Service Request Date / Date or year the customer initially requested the known load to be actively energized.
- Current Expected Energization Date / Date or year the known load is expected to be energized by the utility.
- Status / Status of the known load. Status options include New, Ongoing, Cancelled, Energized, Reactivated, Deprioritized (Removed from Forecast), and Reclassified as Pending Load. The statuses Reactivated, Deprioritized (Removed from Forecast), and Reclassified as Pending Load were introduced to improve project classification and provide greater transparency into project progression and forecast assumptions. Projects classified as Deprioritized (Removed from Forecast) have been removed from forecast assumptions due to lower confidence and are not treated as Pending Loads.

Projects classified as Reclassified as Pending Load have been transitioned to the Pending Load report. Projects with either status are excluded from Known Load Project tracking and metrics. Reactivated indicates a project that was previously Cancelled or Completed but has since become active again and is included in project tracking and metrics.

- Actual Energization Date / Date associated with customer energization. Depending on the methodology used to populate this date in the project tracker, this date may represent either the target customer energization date or the date when customer load began to materialize (service initiation). SCE is working to standardize how this field is populated.
- Actual Load Amount (MVA) Actual load amount being used by the customer. SCE is working to standardize how this field is populated. For reporting purposes, the requested load amount will be used until field population is standardized.
- DUPR ID / Distribution Upgrade Project Report ID for planned project(s) that the known load depends on.

The metrics compare two back-to-back tracking datasets: the prior dataset, Plan Year 2025 (PY25), and the current dataset, Plan Year 2026 (PY26). Each "Tracking Dataset" is a point-in-time snapshot of known load projects. PY25 covers forecast years 2025–2034, and PY26 covers 2026–2035. Only the overlapping years (2026–2034) can be compared, so 2025 and 2035 are left out of the year-over-year change metrics. "MVA" measures load amount, and "count" is the number of projects.

For the percentage-change metrics, the denominator is drawn from the projects in the 2025 GNA/DUPR Known Load Report that qualify as Known Loads. If an ongoing project shows an annual change in a given year but did not have load present in the 2025 GNA/DUPR Known Load Report for that given year, it is treated as zero for that year.

Note: SCE indicated that it 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 2025 and 2026 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 2025 GNA/DUPR Report.

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

- We see from Table 2-7 below that known load counts and MVA for all known loads is substantially less in 2026 than in 2025. On average, counts and MVAs have decreased about 20%. From the table we see that Transportation KL MVA are similarly down about 20% from the previous cycle, however Transportation KL counts have actually increased a small amount in this cycle.
- We believe that one factor that contributed to this general overall reduction in Known Loads is the reclassification of loads that were considered as known loads in the 2025 cycle being reclassified to a pending load category using the newly CPUC approved pending load category definitions for Pending Loads A, B1, B2 and C.

Table 2-7: Known Load Tracking Data Comparison

	2025	2026	Percent Change
Total of All KL			
KL MVA	5685	4469	-21%
KL Count	3342	2581	-23%
Transportation			
KL MVA	1920.4	1388.4	-28%
KL Count	664	676	2%

2.2.3. 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 for the Synthesis Case is significantly greater than the previous cycle by about 270% and by about 680% over the last six years.
- The number of known loads is significantly smaller than the previous cycle by roughly 20%. A contributing factor may be the reclassification of known loads in the previous cycle to pending loads in this cycle.
- On the other hand, total Known and pending loads have grown about 400% over the last five years and 29% over the last cycle if all PLs are included in the count.
- 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 the known loads 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 2027, i.e., the 2027 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 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 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.

3. Review of DUPR Report

Listed below is a high-level summary of the SCE DUPR Report that was filed on August 15, 2026. 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. SCE made several changes to their DUPR report in this cycle compared to the last cycle. SCE implemented the following:

- The CPUC's pending loads resolution
- The CPUC's scenario planning resolution
- A Hot Spot methodology consistent with these resolutions
- A decision logic methodology used to integrate the results of the three scenarios into a single scenario referred to as the Synthesis results

As a result, SCE developed four DUPR reports – one for each of the scenarios and one for the Synthesis Case.

SCE indicated that they evaluated whether higher-growth conditions would result in additional constraints at the same location and whether modifications to project scope, sizing, or timing could efficiently accommodate a broader range of future load outcomes.

The Base Scenario serves as the primary planning scenario and establishes the initial set of projects. The Low Scenario provides insight into the confidence associated with identified needs and is used to prioritize investments.

The High Scenario is used to evaluate future growth risks and assess whether proactive planning measures may provide long-term customer benefits. This scenario is used to augment the investment plan where needed and reasonable.

DUPR Report

SCE indicated that SCE uses three identifiers to facilitate the linkage between the grid needs in its GNA report and the planned investments/candidate deferral projects in its DUPR.

- DUPR Project ID: a project identifier used to associate different components of a single project. For example, a single project that would mitigate needs of multiple assets might have multiple line items in the planned investments list, with each line-item mapping to a circuit that has a grid need being solved by the project. SCE cross-references the current Planned Investments with previous DUPR and DDOR reports up

to 2019 when DDOR Project IDs were introduced. DUPR IDs can be either DDOR Project IDs or DUPR Project IDs depending on what year the project first appeared in the filing.

- DUPR ID: a unique identifier for each line item in the planned investments list.
- GNA ID: a unique identifier assigned in the "Grid Needs Assessment (GNA)" sheet to represent each unique line item in the "Grid Needs Assessment (GNA)" sheet. GNA ID is used for linkage purposes in the Planning Assumption sheets (feeder and substation) and DUPR report.

The 2026 SCE DUPR report includes a narrative along with tab in a combined GNA and DUPR Excel-based workbook called Distribution Project Report. The tab includes both Planned Investments (Funded)" and "Planned Solutions" (Not yet Funded) which are discussed below. 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's 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 in the Synthesis Case

Shown in Table 3-1 are the Planned Investments included in SCE's DUPR report tab. The total number of planned investments in the 2026 DUPR is 1357 projects which compares to 574 planned investments in the 2025 DUPR for a substantial increase of about 240%. The tables show that many projects are in the Metro and Metro West and are predominantly distribution capacity projects in nature.

Table 3-1: 2025 and 2026 Planned Investments by Type

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**

2026 Planned Investments

Region	Project Type			
	Distribution	Distribution VAR	Subtransmission	Total
Desert Region	187	11	35	233
Metro East Region	229	0	17	246
Metro West Region	189	7	15	211
North Coast Region	54	3	5	62
North Valley Region	62	3	15	80
Orange Region	131	5	8	144
Rurals Region	71	4	24	99
San Jacinto Region	84	3	14	101
San Joaquin Region	65	0	9	74
Unassigned	97	0	10	107
Total	**1,169**	**36**	**152**	**1,357**

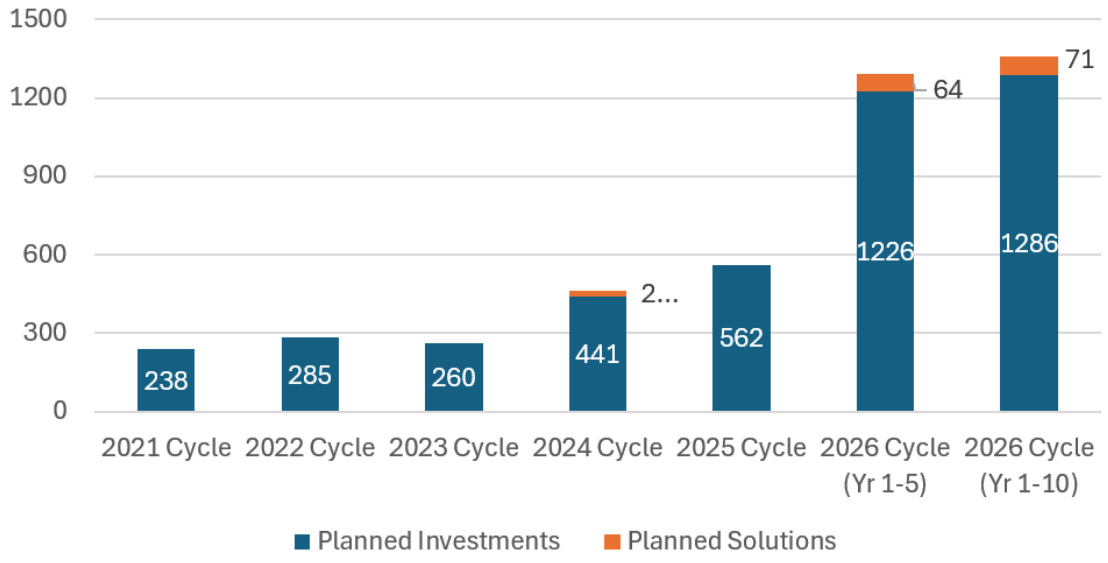
Table 3-2: 2026 Planned Investments by Service

Distribution Service							Total
Capacity	Capacity (UCT)	Voltage	Reactive Power	Reliability, Capacity	Reliability, Voltage	None	
1,197	1200	24	53	172	17	362	**3,025**

Note that the totals in Table 3-1and Table 3-2 are not the same. Table 3-1includes the count of the number of Projects and Table 3-2 is a count of the number of discreet components included in those projects. For example, a project may include the upgrade of two circuits and in that case, it is counted as one project, and it is counted as two components. Thus, the count of projects in Table 3-2 is larger than the count in Table 3-1by a factor of more than 2.

In Figure 3-1 the number of planned solutions and investments is plotted for each of the past 6 cycles. From the plot we see that the number of planned solutions and investments shows a significant growth totaling 570% over that period and 240% growth over the last cycle. We also note that 95% of the planned solutions and investments in this cycle occur in the first five years of the planning period.

Figure 3-1: 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 540% over that period and 240% since the last cycle. This is directionally consistent with the increase in the number of needs in the GNA and the increase in the number of known and pending load projects.

4. Other Items of Interest

4.1. Hot Spots and Developing an Integrated Plan

4.1.1. Hot Spot Methodology and GNA

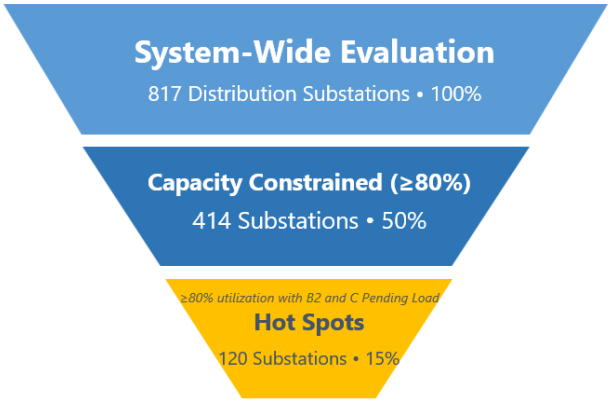
SCE implemented a Hot Spot Methodology for use in the IEPR cap process that included the following features:

- A Hot Spot will be determined on a substation basis
- A substation is a hot spot if:
  - It is "constrained" – that is the forecast loading is greater than 80% of capacity and
  - The sum of B2 and C load on the substation is greater than zero
- Load and capacity are based upon the assumptions and results of the prior DPEP cycle
- Hot Spot calculation is performed for each year of the planning period
- If a substation meets the hot spot test in any year the substation is designated as a hot spot in all years of the planning period after the first year the substation meets the test.
- B2 loads in hot spots are allowed to exceed the IEPR in the Base Case and C pending loads in hot spots are allowed to exceed the IEPR in the High Case.
- Hot Spot determination was done on an annual basis

SCE used a three-step process to determine which substations would be designated as a hot spot as shown in Figure 4-1 below. In that figure we see that SCE has a total of 817 distribution substations that are potential hot spots. Of that group of substations only 120 or 15% of the substations met the load and constrained tests needed to be declared a hot spot.

SCE applied the B2 load in all years of the 10-year planning period if the substation where the load is being served from was determined to be a hot spot in any of the 10-year planning period. Similarly, C PLs were added to the High case using the same approach. We can also see in the figure that 50% of the substations were determined to be constrained – i.e. met the >80% loading threshold. A total of 180 MVA B2 and 412 MVA C loads exceeded the IEPR in the Base and High cases over the ten-year planning period. As noted earlier, this amount is relatively small compared to other load growth components.

Figure 4-1: Hot Spot Summary



Step 1. Adjust the forecast — reset each Distribution Substation forecast to the prior Plan Year baseline.

- Roll back previously modeled capital projects, keeping only no-cost and low-cost solutions.
- Strip out every B2 and C category pending load.

Step 2. Flag grid constraints — recalculate utilization from the adjusted forecast against pre-project planned loading limits.

- Mark any substation at ≥ 80% utilization as capacity-constrained.

Step 3. Pinpoint Hot Spots — layer the current Plan Year pending loads onto the grid-constrained substations.

- Apply the B2 and C pending-load test.
- Substations that are both grid-constrained and carry B2/C pending load are flagged as **Hot Spots**.

4.1.2. Developing an Integrated Investment Plan

Applying the hot spot rules in the GNA and DUPR processes along with the decision logic and other analysis as discussed below resulted in four sets of needs and four sets of projects as described in more detail below.

SCE developed an integrated set of planned investments based upon the information in three scenarios (Low, Base and High) and the application of its decision logic framework and other analysis. The SCE decision logic framework used as input the Base scenario results (Needs and projects) and the High Case results (Needs and projects). SCE summarized its decision logic framework for both distribution projects and subtransmission projects and provided a set of examples for various combinations of Base and High case results. For example, the first three out of five examples provided by SCE for distribution projects are duplicated below in Table 4-1.

Table 4-1: Decision Logic Examples for Distribution Projects

Example	Base Scenario	High Scenario	Decision Logic / Planning Action	Threshold / Key Consideration
#1	No Grid Need / No-Cost Solution	Distribution Circuit Upgrade (DCU)/ New Circuit(s)	No change to Base Scenario scope. Continue with business-as-usual planning because the High Scenario need does not justify additional project scope.	No impact from High Scenario.
#2	Distribution Circuit Upgrade (DCU)	New Circuit(s)	Scope DCU within the applicable planning window. Evaluate new circuit scope only if the Base Scenario average circuit NPL is at or above 400A and the new circuit would substantially improve the DCU solution.	Substantial benefit and average circuit NPL ≥ 400A.
#3	New Circuit(s) / Substation Capacity Upgrade (SCU)	Additional Circuits	Base Scenario already supports substation-related work. Model each additional High Scenario circuit iteratively until the Base Scenario average circuit NPL drops below 400A.	Average circuit NPL ≥ 400A; 4-year window.

It is our understanding that the process used to develop needs and projects for the Low, Base and High cases included the following processes and steps:

- Develop the needs for the three cases using an automated computer script that performs a subset of the full analysis that would normally be utilized to develop needs for the GNA. For example, analyzing whether underground conduit temperatures may be exceeded under forecast loading conditions is not included in the script-based analysis. Also, voltage and VAR analysis is not performed during this process. Thus, this step only identifies thermal capacity needs which is a subset of the total set of grid needs.
- Use a script to develop projects to mitigate the needs identified for each of the three cases in the previous step. This automated process does not break out a project into its components. For example, a project could have multiple components, i.e., a transformer and a circuit upgrade but for this analysis this would be counted as one need not two. Also, projects to address voltage or VAR needs are not analyzed at this point. At this point there are three sets of thermal capacity needs and three sets of projects to address those capacity needs all developed by computer scripts.

The process used to develop projects for the Synthesis Case included the following:

- Starting with the projects developed for the Base and High Cases, use the decision logic to determine if additional projects should be added to the Base projects (that are now the starting point for the Synthesis Case) or if Base Case project scopes or timing need to be modified. These additions/modifications to Base Case projects are the process used to develop the Synthesis Case.
- This decision logic process is performed for all Base Case projects. For all projects in the Synthesis Case, they will have a granularity that includes specifying the components for each project and which results in a higher count than the three case counts.
- Perform additional analysis to develop additional needs as appropriate. For example, underground conduit temperature (UCT) capacity needs would be analyzed and if there was a need due to the forecast of high conduit temperature a need would be added to the Synthesis need list and a project developed to solve that need added to the Synthesis Case project list. Voltage and var projects will also be included at this point along with any resiliency projects. Subtransmission N-1 analysis would be used to determine if any reliability capacity or voltage or var needs exist.
- Develop the optimum set of projects to meet the needs identified in the Synthesis Case starting with fully taking advantage of any No/Low-Cost solutions available.

The result of applying the Hot Spot methodology and the Decision Logic methodology to develop a single integrated investment plan as shown in Table 4-2 and Table 4-3 below. The data is from the GNA and DUPR workbooks included in the Public report.

In the first table we see the count of needs for the three cases and the needs for the Synthesis case. As indicated earlier in the report, the total number of needs for 2025 was 701.

From the first table (Needs) we see that Capacity (UCT) needs and projects are not identified in the Low, Base and High cases and only in the Synthesis case. This makes sense based on our understanding of the process since it does not include UCT analysis in the script for the analysis of needs for the Low, Base and High cases. We also see that the count of needs in the Synthesis case is more than twice the number of needs in the High Case. This makes some sense since the analysis for the Synthesis case is much more elaborate than the analysis for the Low, Base and High cases. We also note that the number of needs in the Synthesis case (1885) is substantially larger than the needs in 2025 (701) by about 270%.

In the second table (Project and Project Components for 2026) we see results for Low, Base and High Cases and the Synthesis Case.

Note the count in the Synthesis column is a count of project components and is higher than the count of projects for that case because a project could have multiple components. The count in the other columns is the count of projects since the count of project components is not available because it was not developed in the process used by SCE as described earlier.

The total number of projects is 1357 in the Synthesis Case while the total number of project components is 3025 (both of which are included in SCE's GNA/DUPR Report). Inclusion of the 3025 project components on a project basis in the table rather than on a component basis is not possible because a project can have two or more components with different categories. For example, a project may have a Capacity component and a Capacity (UCT) component. The number of projects for the Low, Base and High cases should be roughly compared with the count of 1357 projects. For information the number of project components in 2025 was 1066.

- We observe that the count of project components in the Synthesis case is 280% larger than the corresponding value for 2025 driven by significant increases in Capacity and Capacity (UCT) projects.
- We observe that there are no Capacity (UCT) projects in the Low, Base and High Cases but there are such projects in the Synthesis Case. This makes sense since the UCT analysis was only performed in the development of the Synthesis Case results.

Table 4-2: Needs for 2026

	2026 Cases			
Need Categories	Low	Base	High	Synth
Capacity + Reliability Capacity	594	659	748	885
Reliablity Voltage	4	0	5	17
Voltage	3	0	5	24
Reactive Power	3	0	4	49
Capacity (UCT)	0	0	0	692
None	0	0	0	218
Back-Tie	0	0	0	0
Total	604	659	762	1885

Table 4-3: Project and Project Components for 2026

	2026 Cases			
Project Categories	Low	Base	High	Synthesis
Capacity	306	382	411	1197
Reliability Capactiy	30	1	53	172
Reactive Power	3		4	53
Reliabiilty Voltage	4		5	17
Voltage	3		5	24
Capacity (UCT)	0			1200
Back Tie	0	0	0	0
None	0			362
Total	346	383	478	3025

SCE indicated that the 362 planned investments reported with a Distribution Service type of "None" represent planned investments for which a specific Distribution Service classification was not assigned at the time of reporting.

Results of Decision Logic and Scenario Planning

Based upon data requests and discussions with SCE, we learned that none of the 3025 Synthesis Case projects in the table above are the result of the application of the SCE decision logic. They were either identified in the Base Case or developed in the additional planning/analysis processes used to develop the Synthesis Case needs and projects. This later process includes all of the analysis performed for the Synthesis Case that was described earlier. It is not clear from the table above and the other data provided by SCE that there were no projects added as a result of the application of the SCE decision logic.

Based upon the discussion with SCE it is possible that Base Case projects may have had their scope (design and/or timing) modified as a result of the application of decision logic. The IPE plans to examine that question in the 2027 Post DPAG Report.

It appears that the large number of needs and projects in the Synthesis Case is driven by a large increase in load growth and not the result of scenario planning/decision logic. It appears that only the Base Case results were used as a starting point to develop the Synthesis Case; the Low and High Cases for the most part do not appear to have impacted the Synthesis Case projects except for the possibility (not yet confirmed) of changing the scope and/or timing of Base Case projects that were included in the Synthesis Case.

The IPE has not examined why there were no projects in the Synthesis case that resulted from the application of the scenario planning and decision logic but plans to do so as part of the preparation of the Post DPAG Report.

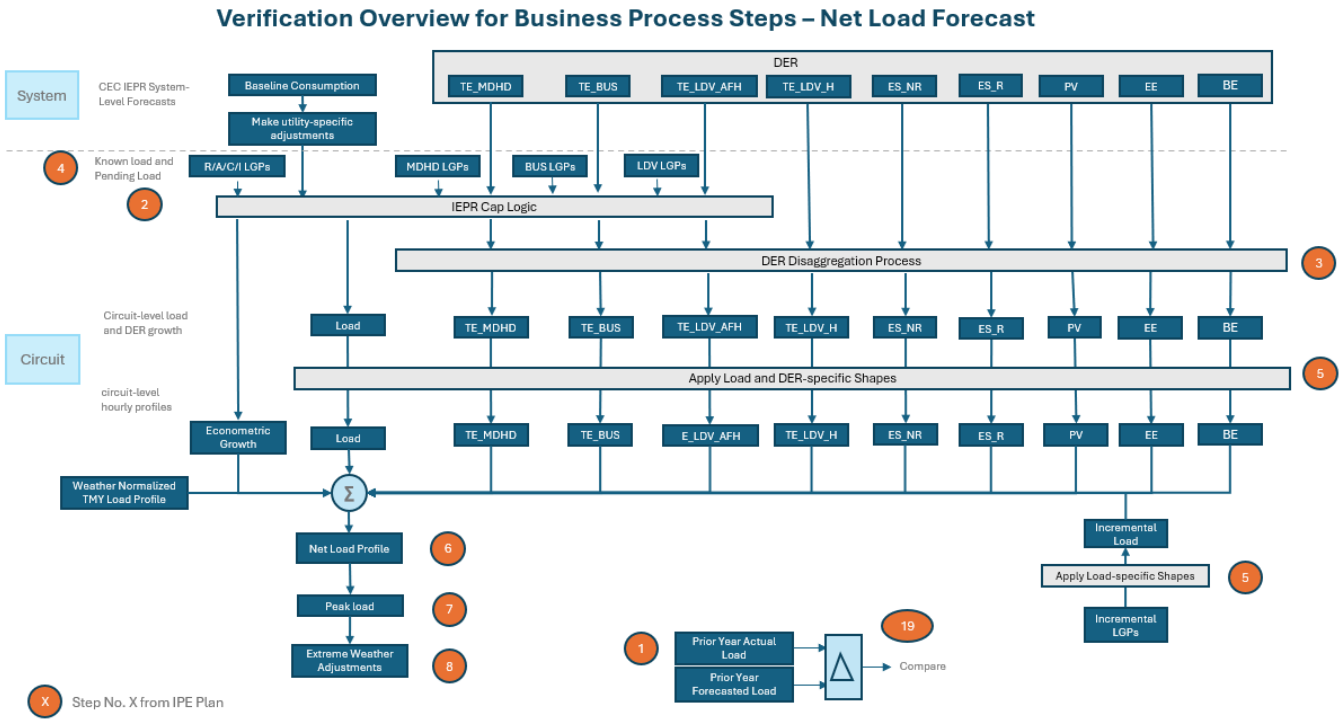
4.2. Miscellaneous – Observations, Conclusions and Recommendations

We recommend that while there were no projects added to the Base Case as a result of applying the scenario planning and decision logic methodology in this cycle, we assume that will likely change in future cycles. For this reason, we recommend that SCE compile information that captures the results of scenario planning and decisions logic to support verification and validation of these processes and results. This information would include recording the projects that were added and projects that had their scope or timing changed as a result of applying SCE's scenario planning/decision logic approach and the rationale for each project addition or project scope or timing change.

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 in Figure 5-1 provides a high-level overview of most steps 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.

Figure 5-1: Business Steps Overview



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 (at the structure level), 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 has made one change to its methodology to incorporate the potential for higher temperatures in the future due to climate change in keeping with CPUC order for IOUs to "integrate climate forecasts using the Shared Socioeconomic Pathway (SSP) 3-7.0[3].

SCE demonstrated their use of 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 Loads.

SCE calculates 1-in-10 load values referred to as Critical Projected Load. The Normal Projected Load under TMY conditions is adjusted to represent a 1-in-10-year extreme temperature scenario (Criteria Projected Load), using historical relationship between customer load and observed temperature within a defined geographic region.

Figure 5-2: Formula to Develop 1 in 10 Loads

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

Summer-peaking circuits	Non-summer-peaking circuits
DRFs are derived from regression-based temperature sensitivity using historical **summer** load-temperature relationships and expected 1-in-10 temperature range influenced by future climate assumptions.	DRFs are derived from regression-based temperature sensitivity using historical **winter** load-temperature relationships and expected 1-in-10 temperature range influenced by future climate assumptions.

We can see from the graphic in Figure 5-2 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

[3] From Climate Adaptation Proceeding, R.18-04-019, D.24-08-005, OP3

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.

Figure 5-3 shows how the DRF is adjusted to capture the potential for higher temperatures in the future as a result of climate change by using an adder to the DRF. A Climate Adder under SSP3-7.0 includes 30 years of simulated historical data (1995-2024) and 30 years of simulated projected data (2018-2047) to estimate how much more intense a 1 in 10 event could be in the future. The climate adder results for 20 randomly selected circuits were in the 1 to 3 degree range.

Figure 5-3: Design Reserve Factor Adjustment for Climate Change

$$\text{Design Reserve Factor (DRF)} = \text{Temperature Sensitivity} \times (\text{Historical 1in10} - \text{Historical Average Max} + \text{Climate Projection 1in10})$$

Temperature Sensitivity (MVA/°F)	Historical 1-in-10 Temperature Range (°F)	Climate Projection 1-in-10 Temperature Range (°F)
How much does load change per 1°F change in temperature?	*How much hotter (°F) is a historical 1-in-10 heatwave vs. average?*	*How much more intense (°F) could a 1-in-10 heatwave be in the future?*
Measure how substation load responds to temperature change.	Measure how historical extreme temperature deviates from average using annual maximum.	Estimates future change in extreme temperatures, relative to historical conditions.
Methodology Unchanged, updated with latest data.	Expanded historical temperature window per EPRI method review (19 -> 30 years)	Adopted regulatory required climate data with expanded historical + projected data (19 -> 30 years)

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, or were incremental known load adjustments, or were a pending load, or were located in a hot spot, 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 Plan defined business steps.

In Table 5-1: Demo for Steps 1and 8 we see part of the demo for Steps 1 and 8 which includes -a tabulation of data for the 20 selected circuits that shows the temperature sensitivity, the temperature range results with and without climate change and the DRF.

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

Circuit Selection

Circuit	Substation	Region
Scholl	Alder 66/12 (D)	Desert Region
Wigwag	Bloomington 66/12 (D)	Desert Region
Pistola	Concho 115/12 (D)	Desert Region
Marendale	Arcadia 66/16 (D)	Metro East Region
Sandy	Bassett 66/12 (D)	Metro East Region
Gerona	Rosemead 66/16 (D)	Metro East Region
Pellet	Center 66/12 (D)	Metro West Region
Blake	La Fresa 66/16 (D)	Metro West Region
Webster	State Street 66/12 (D)	Metro West Region
Empire	San Marcos 66/16 (D)	North Coast Region
Maloy	Saticoy 66/16 (D)	North Coast Region
Mcbean	Newhall 66/16 (D)	North Valley Region
Tetris	Johanna 66/12 (D)	Orange Region
Volpe	Safari 33/12 (D)	Orange Region
Mack	Roadway 115/12 (D)	Rurals Region
Patio	Tortilla 115/12 (D)	Rurals Region
Helicopter	Bunker 115/12 (D)	San Jacinto Valley Region
Equinox	Sun City 115/12 (D)	San Jacinto Valley Region
Argonaut	Triton 115/12 (D)	San Jacinto Valley Region
Hart	Rector 66/12 (D)	San Joaquin Region

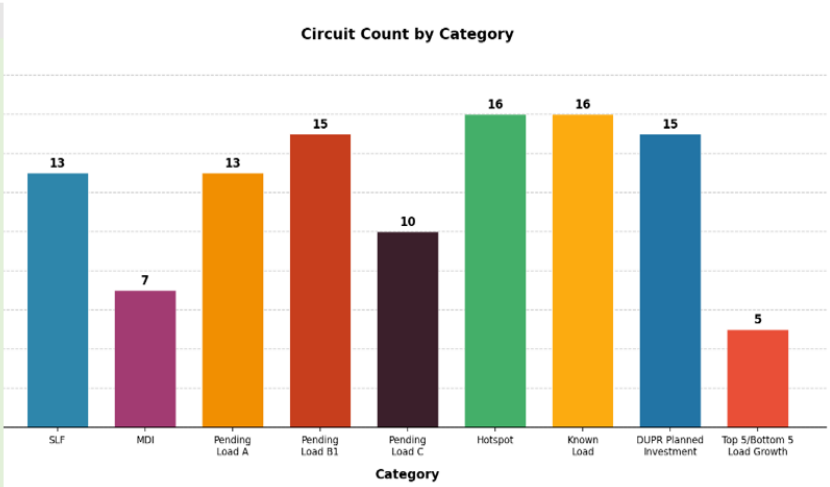


Table 5-1: Demo for Steps 1and 8

Circuit	Substation	Region	Temperature Sensitivity	Temperature Range 1_in_10 (w/o Climate)	Temperature Range 1_in_10 (Climate)	DRF
Scholl	Alder 66/12 (D)	Desert	0.010059826	5.1329304	8.8213654	0.088741
Wigwag	Bloomington 66/12 (D)	Desert	0.009937365	5.3946205	8.8969905	0.088413
Pistola	Concho 115/12 (D)	Desert	0.008866528	4.3554976	7.0565876	0.062567
Marendale	Arcadia 66/16 (D)	Metro East	0.010200517	5.3883337	8.5890837	0.087613
Sandy	Bassett 66/12 (D)	Metro East	0.011614031	5.4524203	8.7607903	0.101748
Gerona	Rosemead 66/16 (D)	Metro East	0.008505933	5.6083514	8.6188614	0.073311
Pellet	Center 66/12 (D)	Metro West	0.010684294	5.8273046	8.6370096	0.09228
Blake	La Fresa 66/16 (D)	Metro West	0.009087605	5.30236999	6.66305999	0.060551
Webster	State Street 66/12 (D)	Metro West	0.004311166	6.1026549	8.2101849	0.035395
Empire	San Marcos 66/16 (D)	North Coast	0.008583313	6.54105388	8.78293388	0.075387
Maloy	Saticoy 66/16 (D)	North Coast	0.004044752	6.0941162	7.8679562	0.031824
Mcbean	Newhall 66/16 (D)	North Valley	0.010911338	4.831169	7.826984	0.085403
Tetris	Johanna 66/12 (D)	Orange	0.002789009	6.0621495	7.8928295	0.022013
Volpe	Safari 33/12 (D)	Orange	0.010218935	5.7757188	8.2512288	0.084319
Mack	Roadway 115/12 (D)	Rurals	0.005978456	4.1353838	7.1895238	0.042982
Patio	Tortilla 115/12 (D)	Rurals	0.008700201	4.6272229	7.4114529	0.064481
Helicopter	Bunker 115/12 (D)	San Jacinto Valley	0.010777873	4.6975389	7.5943489	0.081851
Equinox	Sun City 115/12 (D)	San Jacinto Valley	0.006846778	4.5027959	7.6325759	0.052259
Argonaut	Triton 115/12 (D)	San Jacinto Valley	0.010315245	5.5985428	8.6709128	0.089443
Hart	Rector 66/12 (D)	San Joaquin	0.010837031	4.3657839	7.4830039	0.081094

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.

In the past, SCE started with a single set of IEPR data at the system level and processed it by reducing it for losses and for embedded municipal utility load. In this cycle, in order to accommodate the application of IEPR caps and to improve accuracy, SCE started with multiple data sets at the system level These data sets included the four load growth areas that are subject to IEPR caping – 1) IEPR Base Consumption, 2) IEPR LDV Away from Home charging, 3) IEPR MDHD EV, and 4) IEPR Bus and the following IEPR data sets that are not subject to IEPR Caps - LDV Residential Home Charging, EE, Business Electrification, PV, ES Non-residential, ES Residential.

Shown in Figure 5-5 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 5-5 : IEPR Data Sets used in 2025 and 2026

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

2026-2027 GNA/DPUR Cycle

		2025 -2026 DPP Cycle (2026 GNA)		
		SCE	PG&E	SDG&E
	CEC-Adopted IEPR Vintage:	2024 IEPR Local Reliability Scenario	2024 IEPR Local Reliability Scenario	2024 IEPR Local Reliability Scenario with AAFS 3
Forecast Elements	Economic, Demographic, and Price	Baseline	Baseline	Baseline
	BTM PV and Storage	Low	Low	Low
	Additional Achievable Energy Efficiency (AAEE)	Scenario 2	Scenario 2	Scenario 2
	Additional Achievable Fuel Substitution (AAFS)	Scenario 4	Scenario 4	Scenario 3
	Additional Achievable Transportation Electrification (AATE)	Scenario 3	Scenario 3	Scenario 3

The Excel spreadsheet in Figure 5-6 shows how SCE used CEC IEPR data to develop system level load energy growth for LDV Away from Home Charging, for use in developing annual energy delivered over its distribution system, which is then used in the distribution planning process. The figure also shows the result of the IEPR cap process and how this system level value was checked against a bottom-up summation. We can see that the difference between the system level value and the bottom-up summation is zero for most years and very small when it is not zero.

Figure 5-6: Process to Develop System Load Growth for LDV Away from Home Charging

System Level Adjustment vs Circuit "roll-up" – Light Duty Vehicle (Away from Home) (Base Scenario)

LDV Non-Residential - Away from Home Charging	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total LDV MWh in SCE TAC -Cumulative at CAISO System Level	1,259,615	2,329,263	3,912,162	5,650,718	7,620,810	9,855,497	11,873,067	13,952,721	16,011,039	18,182,785	20,292,084
Distribution Loss	1.081	1.081	1.081	1.080	1.080	1.080	1.079	1.079	1.080	1.080	1.081
TAC-to-System Conversion	1.101	1.101	1.104	1.105	1.104	1.104	1.103	1.102	1.102	1.101	1.101
Total LDV MWh in SCE System MWh-Cumulative	1,058,591	1,957,931	3,280,748	4,734,889	6,390,005	8,270,962	9,971,548	11,729,281	13,458,828	15,286,382	17,061,434
Total LDV MWh in SCE System MWh-Incremental		899,340	1,322,816	1,454,142	1,655,116	1,880,957	1,700,585	1,757,733	1,729,547	1,827,554	1,775,052
EV Away from Home Charging Ratio		0.400	0.410	0.410	0.420	0.420	0.440	0.450	0.460	0.470	0.480
Annual Incremental MWh SCE System		359,736	542,355	596,198	695,149	790,002	748,258	790,980	795,592	858,950	852,025
Adjusted System Level Total After IPER Cap Logic (MWh)		0	0	0	0	244,469	691,473	770,142	762,898	752,339	846,187
Aggregated Circuit Level Total (MWh)		0	0	0	0	244,470	691,476	770,145	762,901	752,342	846,190
Amount Difference (MWh)		0	0	0	0	0.940	2.659	2.962	2.934	2.893	3.254
Difference (%)		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Step	Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	IEPR Forecast (MWH)	359,735.91	542,354.72	596,198.13	695,148.66	**790,001.92**	**748,257.60**	**790,979.92**	**795,591.74**	**858,950.41**	**852,024.98**
2	KL Growth	3,070,298.53	315,046.12	15,457.19	-	-	-	-	-	-	-
	A Growth	1,066,162.43	156,770.24	12,858.09	22,269.80	-	-	-	-	-	-
	B1 Growth	-	3,249,795.63	1,069,212.71	1,109,041.42	9,672.08	56,784.21	20,838.01	32,693.50	106,611.32	5,838.35
	HS B2 Growth	-	-	-	-	-	-	-	-	-	-
	Sum of LGP Can Exceed IEPR	**4,136,460.96**	**3,721,612.00**	**1,097,527.99**	**1,131,311.22**	9,672.08	56,784.21	20,838.01	32,693.50	106,611.32	5,838.35
3	IEPR Remaining for Non-HS B2	-	-	-	-	780,329.84	691,473.39	770,141.91	762,898.24	752,339.09	846,186.63
4	Initial Non-HS B2 Growth	-	-	-	-	-	-	-	-	-	-
5	Non-HS B2 Growth with Rollover	-	-	-	-	-	-	-	-	-	-
6	Scaling Factor for Non-HS B2	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
7	Rollover to Next Year	-	-	-	-	-	-	-	-	-	-
8	Actual Non-HS B2 Included in Forecast	-	-	-	-	-	-	-	-	-	-
9	IEPR Remaining for C	-	-	-	-	780,329.84	691,473.39	770,141.91	762,898.24	752,339.09	846,186.63
10	Initial C Growth	-	503,530.79	2,146.83	15,122.28	15,060.88	-	-	-	-	-
11	C Growth with Rollover	-	503,530.79	505,677.63	520,799.91	535,860.79	-	-	-	-	-
12	Scaling Factor for C	1.0000	0.0000	0.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
13	Rollover to Next Year	-	503,530.79	505,677.63	520,799.91	-	-	-	-	-	-
14	Actual C Included in Forecast					535,860.79					
15	IEPR Remaining for Disaggregation	-	-	-	-	244,469.05	691,473.39	770,141.91	762,898.24	752,339.09	846,186.63
16	**IEPR Reduction**	**359,735.91**	**542,354.72**	**596,198.13**	**695,148.66**	**545,532.87**	**56,784.21**	**20,838.01**	**32,693.50**	**106,611.32**	**5,838.35**

Table 5-2 below shows the development of system level values and the comparison of system value against the bottom-up summation for Business Electrification which is a load growth that is not subject to IEPR caps. Again, the differences are very small.

Table 5-2: System Level Building Electrification and Comparison to Bottom-Up Value

Fuel Substitution (BE)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
SCE TAC MWh-Cumulative at CAISO System Level	482,240	1,366,778	2,853,950	4,453,219	6,109,966	7,624,767	9,103,210	10,540,300	11,723,387	12,374,299	12,886,361
Distribution Loss	1.081	1.081	1.081	1.080	1.080	1.080	1.079	1.079	1.080	1.080	1.081
TAC-to-System Conversion	1.101	1.101	1.104	1.105	1.104	1.104	1.103	1.102	1.102	1.101	1.101
SCE System MWh-Cumulative	405,279	1,148,886	2,393,329	3,731,473	5,123,171	6,398,882	7,645,294	8,860,647	9,854,642	10,403,151	10,834,757
Annual Incremental MWh SCE System		743,607	1,244,443	1,338,144	1,391,699	1,275,710	1,246,413	1,215,353	993,994	548,510	431,606
Aggregated Circuit Level Total (MWh)		743,609	1,244,446	1,338,148	1,391,703	1,275,714	1,246,416	1,215,356	993,997	548,511	431,607
Amount Difference (MWh)		2.086	3.491	3.754	3.904	3.579	3.497	3.410	2.789	1.539	1.211
Difference (%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

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

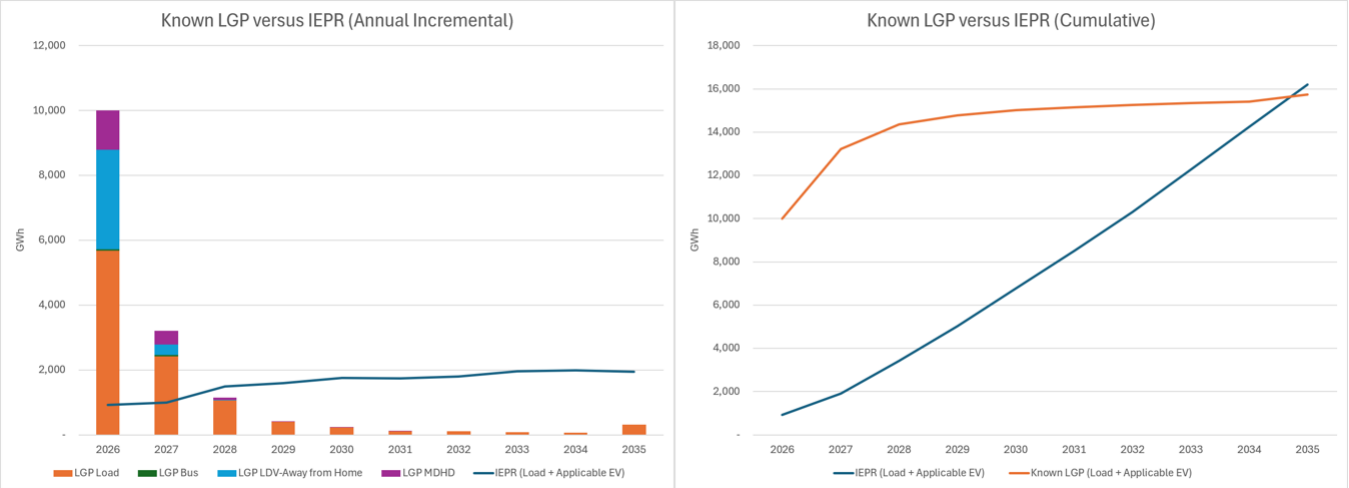
SCE demonstrated how system level values compare to the corresponding aggregate of all circuit level values. The results of the comparison were discussed in the previous section for IEPR load growth components.

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 Load Growth Projects to Circuit Level Forecasts – 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 2026 which are referred to as Incremental Known Load Growth Projects were discussed earlier in the report. During that discussion it was pointed out that in this cycle, Commercial EV charging and cultivation loads which were by far the majority of the incremental known loads, were removed from the incremental loads and if they met the appropriate criteria were included in one of the pending load categories. As a result of removing Commercial EV charging and cultivation the remaining incremental known loads totaled 22 MW over the ten-year forecasting period.

Figure 5-7: Known Load versus IEPR (Annual Incremental)



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, 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 cycle's 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 for the Synthesis Case (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 were 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

In the past, this step normally reviewed the process that SCE used to determine the appropriate planned investment to meet the needs of the GNA Report. As reflected in the approved IPE Plan, in this cycle this section will: 1) review the process used to develop projects for the Low, Base, High and Synthesis Cases and 2) review the portion of this process step that is used to determine if planned investments identified in previous cycles are still needed and the project is still the appropriate solution based upon this cycle's forecast and other related planning assumptions. The process used to develop projects for the Low, Base and High cases included the following:

- Developing the needs for these three cases using an automated script that performs a subset of the full analysis that would normally be utilized to develop needs for the GNA. For example, analyzing whether underground conduit temperatures may be exceeded under forecast loading conditions is not included in the script-based analysis. Also, voltage and var analysis is not performed during this process. Thus, this step only identifies capacity needs.
- Using a script to develop projects to mitigate the needs identified for each case. The granularity of these projects is less granular than normally would be the case because the analysis identifies the number of projects and not the number of various components included in a project. No projects to address voltage or var needs are identified at this point.

The process used to develop projects for the Synthesis Case included the following:

- Starting with the projects developed for the Base and High Cases, use the decision logic to determine if additional projects should be added to the Base projects or if Base project scopes need to be modified. These additions/modifications to Base Case are the process used to develop the Synthesis Case.
- This decision logic process is performed for all Base Case projects. For all projects in the Synthesis Case, they will have a granularity that includes specifying the components for each project.
- Perform additional analysis to develop additional needs as appropriate. For example, UCT capacity needs would be analyzed and if there was a need due to the forecast of high conduit temperature a need would be added to the need list and a project

developed to solve that need added to the Synthesis Case project list. Voltage and var projects will also be included at this point along with any resiliency projects.
- Develop the optimum set of projects to meet the needs identified in the Synthesis Case starting with fully taking advantage of any No/Low-Cost solutions available.

The purpose of this second 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, one at a time, 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 10 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
- Title of Project and Notes: Scope of the project as of the previous cycle
- Planning Year 2025 (PY 2025) Operating Date (OD) Year that the project is planned to be completed as determined in the 2025 cycle planning assessment
- Planning Year 2026 (PY 2026) Operating Date – Year that the project is planned to be completed as determined in the 2026 (current) cycle planning assessment
- Project Still Needed Flag
- PY 2025 Deficiency in (MW, MVAR or VPU for five planning years
- PY 2025 Deficiency in % for five planning years
- PY 2026 Deficiency in (MW, MVAR or VPU for five planning years
- PY 2026 Deficiency in % for five planning years

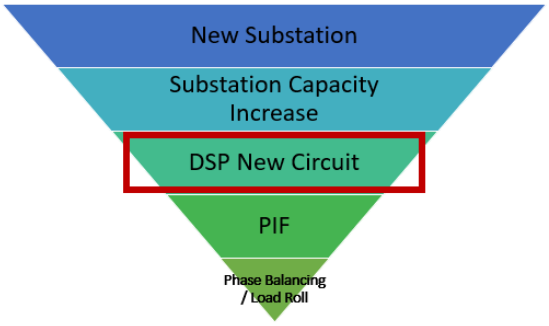
SCE demonstrated this process for ten projects using the data listed above. The demo used the following types of slides accompanied by a data set. Shown in the first figure (Figure 5-8)

below are two examples for distribution projects followed by a figure (Figure 5-9) with a sub-transmission project. The first distribution project example is the Elizabeth Lake 66/16 kV Distribution Circuit Upgrade Project that was created in 2025 that is still needed based upon the most recent assessment but has been delayed (has a later Operations Date (OD) since the first year of need occurs later than in the previous cycle's analysis. The next example is the Tortilla 115/33 Distribution Project that is a project that was not needed in 2025 but is needed in the 2026 GNA results. This assessment essentially confirms that the analysis of this project's needs is still valid and the project is needed with an OD date of 2026.

Figure 5-8: Distribution Examples for Step 13 Process

Elizabeth Lake 66/16 kV Distribution Circuit Upgrade Project

PY 2025 Deficiency (MW, MVAR or VPU)						PY 2026 Deficiency (MW, MVAR or VPU)					
2025A	2026A	2027A	2028A	2029A	Units	2026	2027	2028	2029	2030	Units
1.67	1.88	1.09	2.91	3.24	MW	0.00	2.21	5.70	6.26	6.88	MW



DUPR_2025_759030

Project Scope: "Elizabeth Lake 66/16 kV - DCU - Ukulele 16 kV; Approximately 6 Circuit Miles, 5 New RAG Switches, 5 New Capacitor Banks, and 3 New RCS"

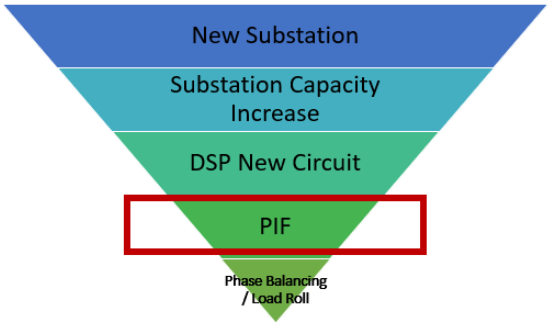
OD: 06/01/2027

Example Type:

- Project is still needed
- Created 2025

Tortilla 115/33 Distribution Project

PY 2025 Deficiency (MW, MVAR or VPU)						PY 2026 Deficiency (MW, MVAR or VPU)					
2025A	2026A	2027A	2028A	2029A	Units	2026	2027	2028	2029	2030	Units
						4.70	6.76	8.96	8.96	8.98	MW



DUPR_2026_772006_detailed

Project Scope: Tortilla 115/33 (D) - Poco 33kV - Line extensions on Poco 33kV to serve large load growth at The Outlets at Barstow and cutover a portion to offload 12kV for smaller customers

OD: 06/01/2027

Example Type:

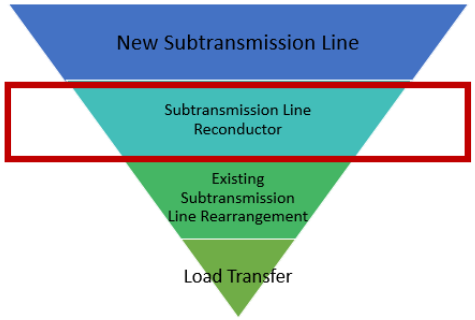
- Project is still needed
- Created 2026

The subtransmission project analysis example below (Saugus-Colossus-Lockheed-Pitchgen 66 kV Subtransmission Line) indicates that the project is still needed but can be delayed by two years.

Figure 5-9: Subtransmission Examples for Step 13 Process

Saugus-Colossus-Lockheed-Pitchgen 66 kV Subtransmission Line

PY 2025 Deficiency (MW, MVAR or VPU)						PY 2026 Deficiency (MW, MVAR or VPU)					
2025A	2026A	2027A	2028A	2029A	Units	2026	2027	2028	2029	2030	Units
0	1	3.5	4.8	6.7	MW	0	3.8	8	12.3	13.2	MW



DDOR_2019_8252

Project Scope:

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

Rebuild 1.82 miles of Pitchgen leg

OD: 06/01/2027 (Original OD 06/01/2025)

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 DEFFERAL 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 2025 and a review of similar analysis for the previous three years. This type of analysis has been included for the last five 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 is 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 two cycles SCE developed and made available data that allowed the IPE to perform this analysis on all of SCE's circuits. In this cycle, data was provided that allowed a comparison of all circuits including those with transfers.

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 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 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 the 2023-2024 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 the 2025-2026 cycle is shown in the figure below (Figure 5-10). Two histograms are included – one for all circuits and a second for all circuits that were not involved with a transfer. In the past, circuits with transfers were excluded from the analysis because accurately capturing the impact of transfers is difficult and thus potentially could introduce errors in the analysis. In this cycle, SCE used transfer data to allow all circuits to be analyzed as shown on the right and only circuits without a transfer as shown on the left. The data suggests that average forecast errors are larger when circuits with transfers are included in the population analyzed. The fact that the averages are both positive (30kW and 90kW) signals that the average error is positive, indicating a slight bias towards under-forecasting.

In the following figure (Figure 5-11) we see a histogram of forecasting deltas for the entire system in percentage format. The data plotted suggests a slight bias toward under-forecasting.

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). We once again see a normal type of distribution and in this cycle's data we see a slight under-forecasting bias.

In the last cycle, we analyzed the forecast error data to determine if load forecasts for circuits with known loads might have larger forecast errors than circuits without 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 a relatively small percentage of the known load projects that were projected to be completed actually completed in 2025. Thus, for the circuits whose

known loads were not completed, it is possible they would have an over-forecast error equal to about the size of the known load.

In the last cycle analyzing the data for circuits without known loads we found a similar and slightly larger bias toward under-forecasting for the circuits with known loads, however, we found a slight bias toward over-forecasting for those with known loads. 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.

Figure 5-10: All Circuits -Percent Difference between Forecast and Actual, with and without Transfers

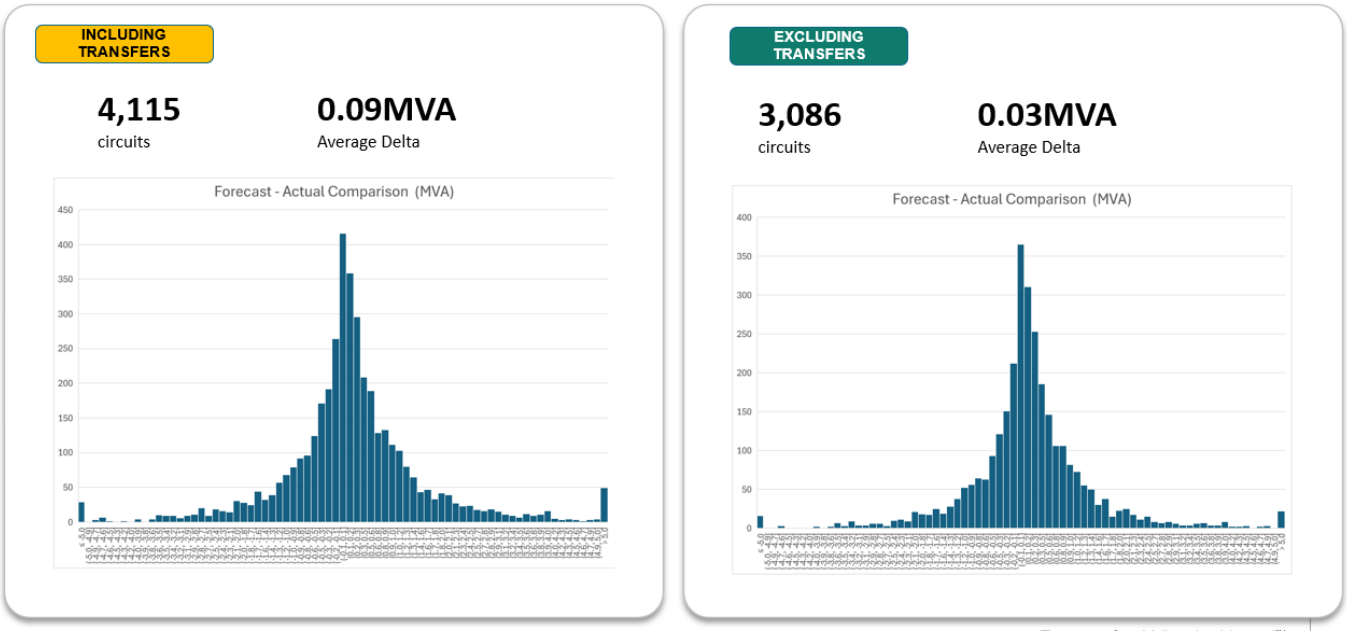
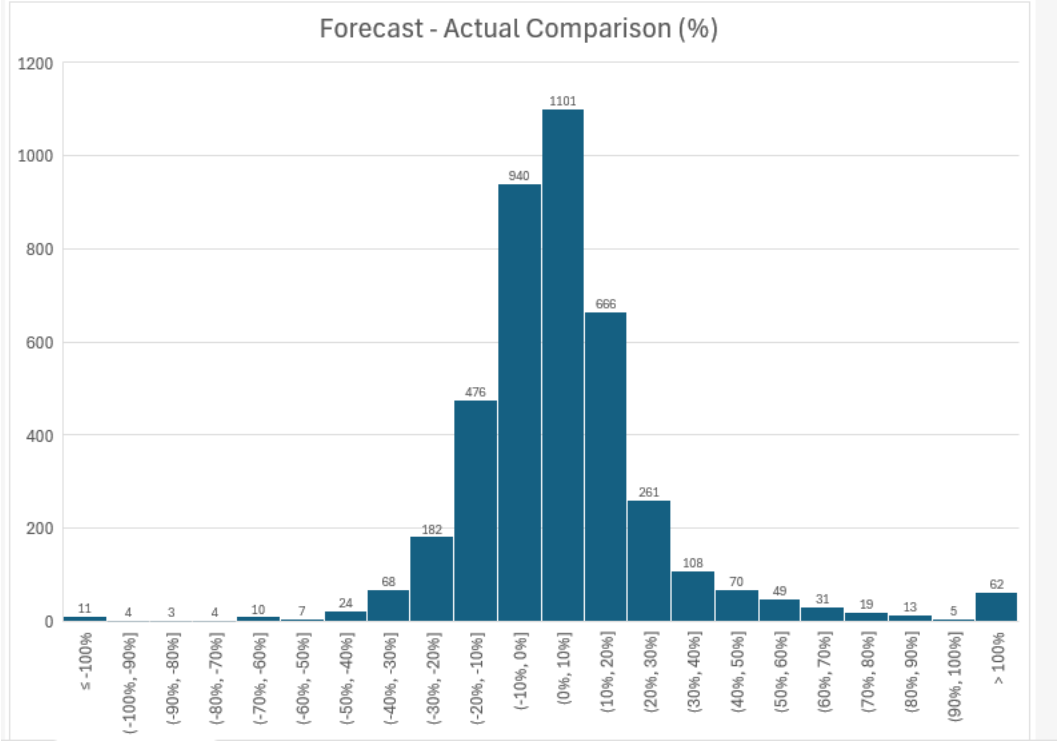


Figure 5-11: All Circuits -Delta Difference % Between Forecast and Actual



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. There were no written follow up DPAG questions directed to the IPE. SCE's responses to the questions directed to them are included in Appendix C.

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 normally would review the process that SCE uses to prioritize planned projects for execution. In this cycle the review was skipped as indicated earlier in the report.

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 2026 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.

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

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;

  - 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.

- 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.

Appendix B Copy of the IPE Plan

Note: The 2025/2026 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 2025-2026 DPEP Cycle - Southern California Edison

Submitted to California Public Utility Commission

August 17, 2026

Submitted by:

Resource Innovations

Sundar Venkataraman

Barney Speckman

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 2025-2026 Distribution Planning and Execution Process (DPEP) 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. Further revisions made to this scope of work are discussed in Section 3.1 of the IPE Plan and reflected in Table 3-1.

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 2026-2027 Distribution Planning and Execution Process Cycle[1] issued on April 20, 2026, and is shown below:

- Draft IPE Plan due week of May 18, 2026.
- Final IPE Plan due August 17, 2026.
- IPE Preliminary Analysis of GNA/DUPR Data Adequacy for all three IOUs due September 4, 2026.
- IPE Distribution Planning Advisory Group (DPAG) report for each IOU presenting GNA/DUPR review findings and Verification & Validation outcomes due November 6, 2026.
- IPE Post DPAG Report covering all three IOUs, comparing their filings, reviewing compliance, and making recommendations for process improvements due March 15, 2027.

[1] The ALJ ruling issued on April 20, 2026 provided the schedule for both the 2025-26 and 2026-27 DPEP cycles.

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. Scenario planning, if applicable, is used to analyze three scenarios – Low, Base and High Scenarios, the results of which are incorporated into a final proposed set of planned solutions and planned projects.

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 2025-2026 DPEP 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 potentially followed by the IPE reviewing underlying data results. 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 and there is no other reason to believe that this step should be included in this year's review.

- Steps 6-7 - Determine Net Load and Peak Load
- Steps 10 - Evaluate 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 and the ED/IPE do not think there is any other reason to include them in this V&V 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.

As in the last cycle, Step 13 (Development of Planned Investments using Planned Standards) will be retained in this cycle to verify and validate the process used by the utilities to determine whether a planned project (i.e., planned solutions and planned investments) identified in a previous cycle is still needed based on the results of the current cycle. .

In addition, the verification and validation of the following steps related to the identification and prioritization of Candidate Deferral Opportunities (CDOs) will no longer be required. However, these steps are left in the IPE plan to preserve the numbers assigned to subsequent steps to avoid any confusion.

- 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
- Step 25 - Track solicitation results to inform next cycle

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 (created in other distribution planning workstreams).

Two steps (Steps 27 and 28) were added in the last cycle and will be included in this cycle and are listed below.

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

Since pending loads and scenario planning are new in this cycle, several of the steps have been updated to include a verification and validation of these new requirements.

The IPE V&V steps for 2025-2026 DPEP 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.

Note: SCE indicated that it would be categorizing pending loads into four categories – A, B1, B2 and C and that it plans to include Hot Spots in its DPEP in this cycle along with the use of three scenarios and decision logic to develop a single proposed set of projects. The V&V plan shown in the table below reflects the above assumptions.

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

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
PROCESSES TO DEVELOP STARTING POINT LOAD, SYSTEM LEVEL VALUES AND DISAGGREGATE TO CIRCUIT LEVEL				
1	Collect 2025 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 and will describe each step in the process from SCADA collection to development of peak values for 1-in-2 and 1-in-10 peaks. 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	August 7, 2026	▪ 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. ▪ Demonstration to include a slide similar to the one used in the previous cycle titled “1-in-2 Typical Meteorological Year (TMY) Normalization” that is populated with data from one of the selected circuits. Demonstration to also show how the results for

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
		adjust to standard conditions required by following steps of the load forecasting process with a focus on the peak day. 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 DPEP.		that circuit in this slide (assumed to be in MWhr) are processed to result in the MW value that is used in Slide 17 (in the last cycle demo PPT) as Normal Weather Load. ▪
2	Determine load and DER annual	Perform Verification and Validation on all aspects of this process.	June 25, 2026	▪ Provide description of CEC IEPR system forecast(s)

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
	growth used in the DPEP including the application of IEPR caps, Known Loads, Pending Loads and econometric loads. Determine load and DER annual growth used in the DPEP for each scenario, as applicable. Step 2(i) – For Base Scenario Step 2(ii) – For High Scenario Step 2(iii) – For Low Scenario	Roles: SCE to demonstrate how it used the CEC IEPR system level (annual energy) load forecasts for setting IEPR load growth caps at the distribution level, as applicable. SCE to demonstrate how the data for known loads for EV chargers is used in conjunction with the CEC IEPR data for EVs without double counting these loads. SCE to demonstrate how known loads and pending loads are used in conjunction with the IEPR caps to determine the load growth used in the DPEP for the three scenarios (Steps 2(i), 2(ii) and 2 iii)). SCE to provide spreadsheet(s) that demonstrates this process. Verification: IPE to review data provided (spreadsheet) and compare to process summary presented by SCE.		used and link to CEC table(s) used, as available. ▪ Provide description of the process if different than used in 2025 and described in 2025 GNA/DDOR ▪ Provide Data/Demo for the V&V of IEPR cap methodology. ▪ Provide available spreadsheet used to implement process with breakouts for all known and pending load values used in the process in each scenario. ▪ Total annual known loads and pending loads that are used in Step 2 for the determination of econometric loads.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
	Determine load growth cap at the distribution level, if used in the DPEP.	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 DPEP. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DPEP.		
3	Disaggregate load and DER annual growth to the circuit level Step 3(i) – For Base Scenario Step 3(ii) – For High Scenario Step 3(iii) – For Low Scenario	Perform Verification for a subset (approximately 10) of circuits selected by the IPE in consultation with SCE for the Base Case and 5 circuits each for the High and Low Cases. 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	July 17, 2026 Note – the cross-check portion of this step (compare results for selected circuits against results used in the following steps) have a Target	Demonstrations and associated spreadsheet data for all three scenarios as appropriate.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
		of load and DERs to the circuit level along with known and pending loads for all three scenarios. Verification: IPE to review demonstration and compare results to process summary presented by SCE. IPE to compare results for selected individual circuits against results used in following steps in the process (starting in Step 4) for all three scenarios. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DPEP for all three scenarios.	Date after the GNA report is filed.	
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 for all three scenarios. Roles:	July 17, 2026	Demonstrations

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
	Step 3a(i) – For Base Scenario Step 3a(ii) – For High Scenario Step 3a(iii) – For Low Scenario	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 for all three scenarios. 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 verified in Step 2 and known and pending loads as appropriate for all three scenarios. 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:		

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
		IPE to review the business process for reasonableness and consistency with objectives of the DPEP.		
4a,	Step 4a – Gather Known Load data (used in Step 2	Perform Verification for a subset (approximately 10) of circuits randomly selected by the IPE in consultation with the IOU for the Base Scenario and 5 circuits each for the High and Low Scenarios. Roles: SCE to demonstrate how it adds known loads for cases where the load is in addition to the CEC system level load forecast. SCE to demonstrate how loads are added and any adjustments to system level values are accomplished. SCE to demonstrate values in Step 4 are consistent with values in Step 2. Verification:	July 17, 2026	▪ Data for all known loads. This data to include unique identifier, type of load, magnitude, timing, and circuit. ▪

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
		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 DPEP.		
4b	Step 4b – Determine Hot Spots	Review the approach, process used and results of the application of the Hot Spot methodology used to determine whether B2 and C loads can exceed the IEPR cap under certain conditions. Role: SCE reviews their approach and process and results in a demo and provides results data for all substations.		• Detailed description of the approach and process used to determine whether a substation is considered a Hot Spot in this DPEP cycle. • Demonstration of the approach and process used. • List of all Substations with an indication of 1) which met or exceeded

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
				the 80% constrained capacity test, 2) which met the load growth test and 3) which were designated as Hot Spots
4c	Step 4c – Gather Pending Loads data used in Step 2 Step 4c(i) – For Base Scenario Step 4c(ii) – For High Scenario Step 4c(iii) – For Low Scenario	Perform Verification for a subset (approximately 10) of circuits randomly selected by the IPE in consultation with the IOU for the Base Scenario and 5 circuits each for the High and Low Scenarios. Roles: SCE to demonstrate how it adds pending loads for cases where the load is in addition to the CEC system level load forecast. This demonstration would include how the result of the Hot Spot methodology impacts the pending loads that are included in all three scenarios – Step 4c(i), (ii), and (iii). SCE to demonstrate how pending loads are added and any adjustments to system level values are accomplished, if any.		• Data for all pending loads. This data to include unique identifier, pending load category, type of load, magnitude, timing, and circuit. • Data for all pending loads including for example, vendor forecast data, SCE Fleet data, truck stop data etc. 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 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
		SCE to demonstrate values in Step 4 are consistent with values in Step 2. Verification: IPE to verify that business process demonstration by SCE is the same as described in SCE documentation. IPE to verify, for all three scenarios, 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 DPEP.		
5	Convert peak growth to 8760 profiles as needed	Perform V&V of the use of new profiles. Provide Data/Demo of the use of new profiles for approximately 5 circuits selected by the IPE in consultation with the IOU. Roles:	June 25, 2026	• Description of the new profiles and the rationale for the changes • Demonstration of the changes and results • Data for selected circuits for load and DERs in tabular view.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
		SCE to demonstrate how it converts load and DER results of previous steps into 8760 values for new profiles. 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 DPEP.		
6	Derive net load profile (skipped in this cycle)			
7	Determine net peak load (skipped in this cycle)			
8	Adjust for "extreme weather"	This verification and validation are included in Step 1.	See Step 1	See Step 1.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
PROCESSES TO DETERMINE CIRCUIT NEEDS AND DEVELOP GNA				
9	Initial comparison to equip. ratings to determine if ratings exceeded	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.	See Step 11	See Step 11
10	Evaluate no cost solutions - incorporate load transfers, phase balancing, correct data errors (skipped in this cycle)			
11	Comparison to equip. ratings to determine if ratings exceeded	Perform Verification for five circuits selected by the IPE in consultation with the IOU. Focus on change to the business process to incorporate a new SCE N-1 planning analysis for B Banks.	September 25, 2026	▪ Description of the new N-1 planning process and the rationale for the new process. Description of process used to determine

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
		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 equipment. The demonstration will include comparisons where no cost load transfers and phase balancing is included for some of the selected circuits. 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 DPEP.		need/deficiency amount. Description of ratings and their basis used in this step. ▪ Demonstration of its use for selected circuits ▪ Results of the new process including number of planned solutions that resulted from this criteria. ▪ 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 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
12	Compile GNA tables showing need amount and need timing, etc. (consistent with IOU's documented planning standards and/or planning process)	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 GNA tables for each scenario in the DPEP in Excel format that can be filtered by the IPE. 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 DPEP.	8/17/26 (Public Information) 8/30/26 (Confidential Information) September 25, 2026	▪ Confidential GNA tables in Excel format provided by mid-August. ▪ Copy of planning standard if different than one used in 2021.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
PROCESSES TO DEVELOP PLANNED INVESTMENTS AND COSTS				
13a	Develop recommended planned projects (solutions and investments); follow the IOU's documented planning standards and/or planning process Step 13a(i) – For Base Scenario Step 13a(ii) – For High Scenario Step 13a(iii) – For Low Scenario	Develop recommended projects (planned solutions and projects) for each of the three scenarios. Perform V&V for a subset of projects selected by the IPE in conjunction with SCE confirming that planning standard/process were followed. This overall step (Step 13) will include three processes – 1) the process to identify the current set of solutions and planned projects identified in the DPEP for this cycle for each scenario (which is covered in Step 13a), 2) the process used to develop solution for single investment plan (which is covered in Step 13b) and 3), the process used to confirm that planned solutions and projects developed in prior cycles are still needed (which is covered in Step 13c). Step 13a	October 9, 2026	• Description of process used to develop proposed planned project to address identified need for distribution and subtransmission projects for each of the three scenarios • 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. • Tabulation all projects from all three scenarios

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
		Develop recommended planned solutions and projects for each of the three scenarios. Roles: SCE to demonstrate the process used and the results for each of the three scenarios. 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 for each of the three scenarios. . Verification:		with an indication of in which scenario each project is proposed to be included.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
		IPE to verify that the SCE demonstration reflects the description of the process described and provided by SCE. IPE to verify that results shown in the demonstration follow the described process are same as included in DUPR. Validation: IPE to review the business process for reasonableness and consistency with objectives of the DPEP.		
13b	Step 13b – Develop solution for single investment plan	Develop a single set of planned solutions/investments that incorporates the results of the Base, High and Low scenario planning results. Perform V&V of decision logic to develop single investment plan. Provide data/table that shows the results of the decision logic for all projects (for example, list of all projects, whether project was identified in the base/high/low case and the decision logic used for the single investment plan). Provide Data/Demo of decision logic used to develop		▪ Description of the process used to develop a single proposed set of planned solutions and projects which incorporates the result of the three planning scenarios. ▪ Describe the decision logic used ▪ Tabulation of planned solutions and projects from each of the three scenarios and the planned solutions

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
		single investment plan for five randomly selected projects by IPE and SCE. Roles: SCE to describe and demonstrate how it developed a single proposed set of planned solutions and projects.		and projects in the single investment plan.
13c	Determine if planned solutions/projects identified in previous cycles continue to be needed and are the appropriate solution to meet the need.	Determine if planned solutions/projects identified in previous cycles continue to be needed. Roles: SCE to demonstrate/describe how it determined which projects identified in previous cycles are still needed and that the proposed solutions continue to be the appropriate solutions to meet the need or that project scope has been modified or the project is no longer needed and has been removed from the plan.		▪ Description of the process used to confirm that existing planned solutions and projects are 1) still needed as is, 2) needed but scope has changed or 3) no longer needed. ▪ Description of the process used revise the scope in the event the scope needs to be modified and the process used for solutions or projects that are no longer needed. ▪ Data set containing all planned solutions and

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
				projects (developed in previous cycles) with an indication of the results of the confirmation process for each to include whether each project was a) still needed as is, b) scope needs to change (timing), c) scope needs to change sizing, project non longer needed, d) project retained because it is too late in the project to cancel. ▪
14	Estimate capital cost for Candidate Deferral Projects (skipped in this cycle)			▪
PROCESSES TO DEVELOP CANDIDATE DEFFERAL LIST AND PRIORITIZE				
15	Development of Candidate			

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
	Deferral Projects list through application of screens (timing and technical) (skipped, no longer required)			
16	Development of operational requirements (daily, monthly annually etc.) (skipped, no longer required)			
17	Prioritization of candidate deferral projects into Tiers (skipped, no longer required)			▪
18	Calculate LNBA ranges and values for all planned investments			

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
	(skipped, no longer required)			
19	Compare 2025 forecast and actuals at circuit level for all distribution circuits	Perform comparison of forecasted and actual loads for all distribution circuits excluding circuits with load transfers. Roles: SCE to demonstrate comparison of 2025 actual loads (as recorded and as adjusted) against the forecasted 2025 load values from the 2025-2026 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 DPEP.	August 28, 2026	Forecasted peak load data for 2025 from the 2025-2026 DIDF cycle and recorded peak load data for 2025 from the 2025-2026 DIDF for all circuits. Comparison data for all circuits analyzed.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
20a	Analyze known load tracking datasets and verify the calculation of known load metrics.	The IPE to calculate selected 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 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 used in the 2025/26 DPEP cycle and make recommendations for changes based on discussions with SCE. The data to be provided by SCE will include known 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	August 28, 2026	Confidential version of the known load tracking dataset included in their 2026 GNA-DUPR filing. Description of the tracking data set included in their 2026 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 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
		included in their narrative of the known load tracking dataset. Verification: 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.		
20b	Analyze pending load tracking dataset and verify the calculation of pending load metrics, as applicable – including review of categorization of PL and	The IPE to review the pending loads tracking data format, definitions, and processes and reporting that the utility used in the 2025/26 DPEP cycle. If applicable, IPE to also review the calculation of pending load metrics. Roles: SCE to provide the confidential version of the pending load tracking dataset included in their 2026 GNA-DUPR filing. SCE to also provide		Categorization results (table with pending load showing which PL category that it belongs to and confirming that all minimum criteria have been met) For 10 randomly selected pending loads by the IPE and IOU, provide supporting information for each criteria that

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
	supporting information.	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 pending load tracking dataset. SCE to demonstrate the process used for categorization of PL into A, B1, B2 and C and supporting information. Verification: IPE to analyze the pending load tracking dataset provided in the 2026 GNA-DUPR filing and verify the pending load metrics calculated by the utility. Validation: IPE to review the approach and process used by the utility to calculate the metrics using pending load tracking dataset.		needs to be met for inclusion in its category.

OTHER IPE WORK

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
21	Optional - Review plan for changes to the planning process for the next cycle (skipped, no longer required)		N/A	
22	Review implementing of planning standard and/or planning process (skipped, no longer required)		N/A	
23	Review list of internally approved capital projects (skipped, no longer required)		N/A	
24	Respond to and incorporate DPAG comments	Include in Final IPE Report.	As needed.	

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
25	Track solicitation results to inform next cycle (skipped, no longer required)		N/A	
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. 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.		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 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.

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
		b. Date: October 20, 2026 - The IOU will review all the documents[1] 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 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 October 20, 2026 (the body of the report to include all but the documents provided in previous item) for final IOU confidentiality review.		

[1] 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 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
		d. IOU checks the draft confidential report for confidentiality and correctness and provides their comments/markups by October 30, 2026. e. After review and signoff, the IPE produces the final confidential and draft reports by November 3, 2026. f. IOU requests CPUC confidential treatment using standard procedures. g. IOU files public version of the IPE report based on the schedule provided by the CPUC November 6, 2026 h. IOU files revised public report if CPUC rejects any requests for confidential treatment; otherwise, process is complete, and no further action is needed.		

IOU Business Process / IPE Review Step	Business Process / IPE Review Step Description	Plan for 2025-2026 DPEP Cycle	Target Timing	Data/Information Requirements
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.	October 13, 2026	TBD
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.	October 13, 2026	TBD

Appendix A CPUC 4/13/20 Ruling Excerpts

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;

  - 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.

- 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.

- 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



California Office

719 Main Street

Half Moon Bay, California 94019

Tel: +1 650 761 6456

Submitted by:

Sundar Venkataraman

Barney Speckman

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 the documents that are declared confidential and are not available to the public.

C.1 List of Documents Provided – Public Set

- GRC (1)_Public
- GRC_Workpapers (1)_Public
- R2106017-SCE 2024 GNA-DDOR Report-Public

C.2 List of Documents Provided – Confidential Set

- Confidential_PY26_Known_Loads_Projects Report_V2_IPE (1)
- Confidential_RG_Pending Loads PY2026_B2&Hotspots (1)
- Confidential_SCE PY26 V&V Step 2 IEPR Cap for Consumption
- Confidential_SCE PY26 V&V Step 2 IEPR Cap for DER_EV
- Confidential_SCE PY26 V&V Step 3 Base DER_Consumption Adjustment Worksheet
- Confidential_SCE PY26 V&V Step 3 Consumption Disaggregation Tables
- Confidential_SCE PY26 V&V Step 3 High DER Adjustment Worksheet
- Confidential_SCE PY26 V&V Step 3 Low DER Adjustment Worksheet
- Confidential_SCE PY26 V&V Step 3 Whirlpool Adjustments for DER and Consumption - High
- Confidential_SCE PY26 V&V Step 3 Whirlpool Adjustments for DER and Consumption - Low and Base
- Confidential_SCE PY26 V&V Step 4 LGP versus IEPR Charts
- Confidential_SCE PY26 V&V Step 4_Known_Load_Data
- Confidential_SCE PY26 V&V Step 5 DER SHAPE FILE (non TE)
- Confidential_SCE PY26 V&V Step 5 DER SHAPE FILE (TE)
- Confidential_SCE PY26 V&V Step 5 LGP SHAPE FILE

C.2 List of Documents Provided – Confidential Set (Continued)

- Confidential_SCE PY26 V&V Step 19 Forecast Comparison - System Wide (1)
- Confidential_SCE PY26 V&V Step_4_Pending_Load_Data
- Confidential_SCE.PY26.IPE_Step 12_13 (1)
- Confidential_SCE.PY26.IPE_Step 28
- Confidential_SCE.PY26.IPE_Steps 2_5 (1)
- Confidential_SCE.PY26.IPE_Steps 3_4 (Final)
- Confidential_SCE.PY26.IPE_Steps 19_20
- Confidential_Step 13 Circuit_IPE (1)
- Confidential_TN262282_20250321T133807_CED 2024 Hourly Forecast - SCE - Local_Reliability - correction 3...
- Confidential_TN262788_20250424T111137_CED 2024 Reliability Scenario LSE and BAA Tables_New

C.3 Post DPAG Questions and Responses from SCE are included on the following pages.

SCE Responses to Questions Served on the R.21-06-017 Service List re: SCE's 2026 DPAG Presentation

Oct. 5, 2026

I. DPAG questions SCE received from Energy Division

(1) Please explain further how known loads that are partially energized are represented within the known load tracking data. How does the tracking data represent the amount of initially requested load energized, and the amount of initially requested load which remains to be served?

a. How do you treat partially energized known load into a subsequent DPEP cycle? How does the utility know and prevent double count the investment planning needed to serve the full load of the customer? For example, a 10 MW known load that gets 75% energized. How is this project counted in the following year?

Projects that are partially energized remain in the known load tracking dataset as ongoing projects, with only the unserved portion of the requested load forecasted in future years. Partial energization can be identified by an energization date that has already occurred while the project status remains ongoing.

Partially energized projects are validated for their remaining unserved load, and only that remaining amount is included in future planning to avoid double counting previously energized load.

b. How does the Known Load tracking data indicate which requests lead to additional investment planning needs, and which requests can be served by existing capacity?

The Known Load Tracking Data uses the DUPR ID field to identify known loads associated with planned distribution investments. A DUPR ID links a load request to one or more Distribution Upgrade Project Report projects. If no infrastructure upgrade is required, the DUPR ID may be reported as N/A.

In general, known loads with one or more DUPR IDs contributed to the evaluation or development of distribution investments, while loads without a DUPR ID were determined to be serviceable using existing system capacity. Because system impacts can overlap, multiple known loads may be associated with a single upgrade project, and a single load request may be linked to multiple projects.

(2) Please further explain the 1802MVA drop of known loads from the 2025 to 2026 GNA DUPR (see below) including total MVA amount energized, cancelled, and other factors.

(2025 GNA/DUPR – 5685MVA total from 2025 to 2034)

Total MVA of all known loads by year:

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Grand Total
PY24	1875.0	1047.6	462.1	327.1	137.1	53.0	113.9	29.9	36.4	31.7		4113.7
PY25		2544.3	1605.7	617.8	442.9	145.0	152.8	54.2	69.0	35.3	18.4	5685.4

(2026 GNA/DUPR – 3883MVA total from 2026 to 2035)

Total MVA of all known loads by year:

Forecast Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Sum of Load Amount	2394.8	788.6	289.3	115.1	63	26	30.4	23.6	22.5	129.7

The drop is primarily attributable to project reclassification between 2025 GNA/DUPR (PY25) and 2026 GNA/DUPR (PY26). In PY25, the Known Load total number included projects that are currently categorized as both Known Load and Pending Load. In PY26, only projects classified as Known Loads are included.

From PY25 to PY26, approximately 1,380 MVA across 410 projects were reclassified from the Known Load to the Pending Load portfolio and are therefore no longer included in the PY26 Known Load total.

In addition, from PY25 to PY26 reporting cycles, approximately 360 MVA across 417 projects were energized and approximately 938 MVA across 303 projects were cancelled. And then in PY26, SCE had an addition of about 1,065 MVA across 588 new Known Load projects.

As a result, the change between the PY25 and PY26 Known Load totals reflects a combination of (1) the reclassification of projects to the Pending Load category, (2) normal portfolio attrition through project energizations and cancellations, and (3) the addition of new Known Load projects.

(3) Please provide further explanation how and why the Synthesis Scenario has significantly larger grid needs and planned investments compared to the other scenarios. During the DPAG meeting, SCE explained that their engineers did detailed reviews on the base scenario to identify needs, which included additional needs the automated script was not able to capture, to create the Synthesis Scenario. Prior to the implementation of Scenario Planning, did SCE use a similar process to create their needs and planned investments prior?

Yes. Prior to the implementation of Scenario Planning, SCE engineers performed detailed engineering reviews of the Base Scenario to identify grid needs and develop planned investments. The Scenario Synthesis process continues this evaluation approach by incorporating detailed engineering review beyond the initial automated script outputs.

The Scenario Synthesis may result in a greater number of identified grid needs and planned investments than the individual scenario outputs for several reasons:

- Engineering Review Beyond Automated Analysis - The Scenario Synthesis incorporates detailed engineering analysis by engineers, while the scenario-specific outputs are generated through the scripting process. The engineering review may identify additional needs and solutions that are not captured through the scripted analysis process.
- More Granular Representation of Solutions **-** In the scripted scenario outputs, certain solutions may be represented as a single investment. For example, a new circuit may be reported as one investment. During the Scenario Synthesis process, that same solution may be represented as multiple planned investment components, resulting in a higher count of planned investments.
- Expanded Evaluation of Distribution Services - The scripted analysis primarily identifies solutions associated with capacity-related violations. The Scenario Synthesis incorporates additional engineering review that evaluates other types of constraints, such as capacity duct bank violations and other distribution service types, which results in the identification of additional grid needs and planned investments.

As a result, the Scenario Synthesis reflects both the automated scenario outputs and the additional insights obtained through detailed engineering review, which can increase the total number of reported grid needs and planned investments relative to the individual scenario results.

(4) PG&E only question (SCE abstains)

(5) SDG&E only question (SCE abstains)

(6) In the DPAG presentations, grid needs and planned investments were summarized by distribution service (Capacity, Voltage, Reliability (Back-tie), Resiliency, and for PG&E, "Other"). Are any Planned Investments or Planned Solutions in the GNA/DUPR mainly driven by reliability performance, for example circuits identified through reliability metrics such as those reported in the Annual Electric Reliability Report?

No, the annual Distribution Planning Process (DPP) is focused on capacity driven needs resulting from increased load and DER adoption. The deficiencies categorized as reliability

under the Distribution Service Required (DSR) type are driven by criteria violations identified under N-1 conditions.

a. If so, how are these projects identified or distinguished in the GNA/DUPR (e.g., a distribution service category, primary driver, or project type)?

These projects are not listed in the GNA and DUPR reports.

b. If reliability-driven investments are planned or tracked through another process or regulatory filing, please identify it.

Reliability driven investments are planned via reliability studies as discussed in SCE's General Rate Case (GRC).

(7) The project prioritization methods presented in the DPAG presentations reference reliability-related factors to different degrees. How are reliability considerations, such as historical outage performance or outage risk on specific circuits, factored into your prioritization of distribution planning projects, and what data or metrics inform that assessment?

When prioritizing the capacity projects resulting from the annual DPP, the availability of execution resources is considered. The availability is also impacted by other programs identifying work on the distribution system, which includes reliability driven projects. Additionally, the secondary benefit that a capacity project may have if there are known reliability concerns is considered in the project's benefit after all capacity benefits have been prioritized.

(8) Please confirm what, if any, changes were made to the proposed scenario planning Decision Logic Framework intended for the 2026-2027 DPEP cycle when compared to the Decision Logic Frameworks approved for the 2025-2026 DPEP cycle.

No changes were made to the proposed Decision Logic Framework for the 2026-2027 DPEP cycle relative to the framework approved for the 2025-2026 DPEP cycle. The proposed framework maintains the same core decision-making methodology and principles previously approved by Energy Division. SCE notes that the duration between stakeholder review opportunities at DFWG in May and DPAG in September provided limited time to evaluate and incorporate potential enhancements. While this timing did not result in changes to the proposed framework, the additional time available before the 2027 DPAG should provide a greater opportunity to further refine and improve the framework.

(9) Please explain the relationship between the Annual Electric Reliability Reporting Metrics and the GNA/DUPR. Are the investments needed to remediate the worst performing circuits and other reliability performance metrics integrated into the

GNA/DUPR? If yes, explain how. If not explain why and what other process is used to address the reliability metrics.

There is no existing relationship between the metrics used in the Annual Electric Reliability Report (AERR) and the metrics used in the GNA/DUPR as they are derived from separate processes within SCE. Although the DPP studies consider the scope identified in the reliability studies to ensure consistent modeling of planned system configurations, the investments needed to remediate the worst performing circuits are not integrated into the GNA/DUPR reports as they are not addressing capacity needs. The process SCE utilizes to address reliability needs is outlined in SCE's GRC filings.

II. DPAG questions we received from the Public Advocates Office

Questions on Known Load Project Data:

1. Derating: SCE states that the "Expected Load Amount" field in the Known Load Report "does not reflect any adjustments applied through SCE's load forecast process."

a. Does SCE derate known loads when adding them into the forecast?

Yes. The load incorporated into SCE's forecast is derived from the customer-requested load by applying both a discount factor and a load shape factor. The discount factor accounts for the fact that the customer's maximum requested load is not expected to fully coincide with peak system loading. The shape factor adjusts the load based on the expected usage patterns of the load type, since different load categories contribute differently to system peak demand. As a result, the forecasted load may differ from the Expected Load Amount reported in the Known Load Report.

b. If so, under what circumstances does SCE derate known loads when adding them into the forecast?

For all known load projects, SCE applies a discount factor and a load shape factor based on the project's load type to reflect the expected contribution of the load to system demand.

c. If so, how does SCE calculate the derated value which is added to the forecast?

SCE calculates the forecasted load by applying both a discount factor and a shape factor to the customer-requested load. The resulting forecasted load is calculated as:

Forecasted Load = Requested Load × Discount Factor × Shape Factor

2. Actual Load Amount: SCE states "SCE is working to standardize how this field is populated. For reporting purposes, the requested load amount will be used until field population is standardized."

a. Will SCE provide an updated version of the 2026 Known Load data when this field population is standardized?

Efforts to improve the data being reported will be reflected in future reports. There is no intent to update the already published information.

3. Deferrals: SCE reports 1200 deferred known loads and 1,866 MVA of deferred service. This represents known loads which were present in both the 2025 and 2026 Known Loads databases and now have a later in-service date.

a. What are the key reasons why deferrals occur?

SCE does not currently track the specific reasons why known load projects are deferred. However, deferrals may occur for a variety of reasons, including changes to customer development schedules, permitting or construction delays, modifications to project scope, changes in customer demand projections, utility infrastructure readiness constraints, or changes to planned energization timelines.

b. How many deferred known loads were deferred due to customer behavior – e.g., customers delaying their application, or not being ready to energize on the initial timeline?

SCE does not currently track or categorize deferrals by cause. Therefore, SCE cannot determine how many deferred known loads were attributable to customer-driven factors.

c. How many deferred known loads were deferred due to project delays from SCE – e.g., SCE's capacity or energization work taking longer than originally planned?

SCE does not currently track or categorize deferrals by cause. Therefore, SCE cannot determine how many deferred known loads were attributable to utility-driven factors.

d. When SCE defers a known load, how does SCE ensure that specific known load is not double-counted in the forecast the following year?

When a known load is deferred, it continues to be tracked as the same ongoing project rather than being treated as a new load request. SCE routinely obtains status updates on customer projects and updates the project's information throughout its lifecycle, including expected in-service dates and load assumptions. In addition, SCE's forecasting process is refreshed annually using updated customer baseline consumption and revised load growth assumptions. As a result, deferred projects are carried forward and re-evaluated as part of the updated forecast rather than being added on top of previously forecasted amounts. This process helps ensure that deferred known loads remain appropriately represented in the forecast and are not double-counted in subsequent planning cycles.

Questions on Pending Loads and Hotspots:

4. Hotspot Criteria: OP 6 of Resolution E-5413 states SCE "shall define hot spots as:

(i) a geographical area that is served by electrical infrastructure that is forecasted to experience substantial load growth from any of these sources of load: IEPR disaggregation, known loads, Category A, and Category B1 pending loads, and

(ii) that area includes specific electrical infrastructure, i.e., substations and circuits which are forecasted to be capacity-constrained within the ten year planning period.

(iii) An area is capacity constrained if the total capability of its infrastructure is only marginally greater than the demand served by the infrastructure after all low cost/no cost solutions have been considered. A hot spot will be considered a constrained area if the total demand from the aforementioned load sources, is greater than or equal to 80% of the total capacity.

(iv) If this occurs, all Category B2 pending loads served in the specific capacity constrained area may exceed the California Energy Commission's Integrated Energy Policy Report if necessary."

a. How does SCE identify hot spots?

Hot Spots were identified utilizing the forecast developed in the previously completed plan cycle (2024-2025). The forecast was modified to remove non-low cost and non-no cost solutions. Additionally, load growth that met the criteria for B2 load was also removed from the forecast. Category C growth types were not included in the 2024-2025 plan cycle. The capacity constraint calculation was performed at the substation level utilizing the modified loading values. The substation was classified as capacity constrained if the calculation for any year within the forecast was greater than or equal to 80%. Any substation that was calculated to be capacity constrained and experiencing load growth was classified as a Hot Spot. The list of Hot Spot substations was further filtered to only apply to substations with category B2 and C growth identified for the current plan cycle (2025-2026) as these were the only substations that would be impacted by the classification.

b. How does SCE satisfy the requirements of OP 6 (i) – "substantial load growth from any of these sources of IEPR disaggregation, known loads, Category A, and Category B1 pending loads"?

If a substation was calculated to be capacity constrained utilizing the modified growth, any growth at that substation was considered substantial due to the limited availability for that substation to serve new load.

c. Does SCE use the presence of Category B2 or C pending loads to identify hot spots?

The presence of category B2 or C load was utilized to further filter the list of substations identified as Hot Spots.

d. If so, how does SCE justify the use of B2 and C pending loads to identify hot spots, when the use of B2 and C pending loads to identify hot spots is not permitted under OP 6?

The Hot Spot designation only impacted the amount of category B2 and C load included in the Base and High scenarios. Filtering the list of Hot Spot locations removed the Hot Spot designation from substations with no forecasted category B2 or C load, which had no impact on the final forecast developments.

5. B2 and C Pending Loads: OP 15 of Resolution E-5413 states SCE "shall report in their annual Grid Needs Assessment and Distribution Upgrade Project Reports, at minimum, data on studies used as the basis of pending loads: Source of information (e.g., study, forecasting models, etc.), Data Access (e.g., links to public data, or provider of data if not publicly available), Detailed Methodology (including how data sources are translated into Pending Loads), and Categorization of Pending Loads obtained from the study (Category B2 or C), hot spot location, if applicable."

a. Has SCE identified B2 or C pending loads based on studies?

Yes, category B2 growth was informed by the *Final Report: Interstate 5 Corridor California, Oregon, Washington,* from the West Coat Clean Transit Corridor Initiative and Guidehouse's Transportation Electrification Proactive Planning Framework.

b. If so, where has SCE provided information on these studies as required by OP 15?
The sources are discussed in Section 6.1, "*Pending Load Inputs and Data Sourcing,"* of the GNA/DUPR Narrative.

<u>Questions on Grid Needs and Planned Investments:</u>

6. Scenario Integration: SCE produced three distinct GNA and DUPR outputs for three scenarios, plus a Scenario Synthesis. SCE reports 1,885 Grid Needs and 1,357 Planned Investments in the Scenario Synthesis. However, the High scenario data includes only 762 Grid Needs and 479 Planned Investments.

a. How does SCE combine the Low, Base, and High scenarios into the Scenario Synthesis?

See GNA/DUPR Narrative, Section 8.2.3.

b. Why does the Scenario Synthesis produce more grid needs and planned investments than the High scenario?

(See response for ED Question #3)

c. Compared to the Base scenario, how much added MW of planned capacity is included in the Scenario Synthesis?

SCE does not calculate or track a metric that quantifies the incremental MW of planned capacity attributable to the Scenario Synthesis relative to the Base Scenario. Accordingly, this information is not readily available.

d. Compared to the Base scenario, approximately how much more planned spending (in dollars) is produced by the Scenario Synthesis?

SCE does not calculate or track a metric that quantifies the incremental planned spending attributable to the Scenario Synthesis relative to the Base Scenario. Accordingly, this information is not readily available.

7. Planned Investments: SCE identified the following number of planned investments in its 2021, 2022, 2023, 2024, 2025 and 2026 GNAs. SCE's planned investments have increased significantly between 2021 and 2025, and more than doubled between 2025 and 2026.

Operating Date								Total
2021	2022	2023	2024	2025	2026	2027	2028	
93	95	35	7	5	1	0	2	**238**

Operating Date										Total
2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
102	121	37	13	9	1	1	1	0	0	**285**

Operating Date										Total
2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
87	85	56	20	8	3	1	0	0	0	260

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

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

Operating Date										
2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
273	397	285	215	75	26	25	27	19	15	**1,357**

a. Which key factors in SCE's GNA are driving the overall increase in grid needs across GNA cycles?

The increase in reported grid needs and planned investments across DPP cycles is driven by several factors. First, SCE has observed increasing load growth forecasts over time. Second, SCE's reporting methodology has evolved to provide a more granular representation of planned investments. In prior reporting cycles, certain solutions may have been reported as a single project, whereas more recent reporting reflects individual project components separately. As a result, the reported number of planned investments may increase without a corresponding proportional increase in the underlying scope of work. Third, the planning horizon has expanded over time. Evaluating a longer planning period allows SCE to identify additional future grid needs and planned investments that would not have been captured under a shorter planning horizon.

8. Planned Investments by Distribution Service and Operating Date. On page 59 of the SCE 2026 GNA and DUPR, SCE reports 3,025 total planned investments by Distribution Service and 1,357 total planned investments by Operating Date.

a. Why are there more planned investments when counting by Distribution Service than when counting by Operating Date?

The reported totals differ because a single planned investment may address multiple Distribution Service categories. When investments are summarized by Distribution Service, the same investment may be counted in more than one category. When investments are summarized by Operating Date, each planned investment is counted only once. Accordingly, the total number of planned investments by Distribution Service is greater than the total number of unique planned investments by Operating Date.

b. What are the 362 planned investments with "None" as a type of Distribution Service?

The 362 planned investments reported with a Distribution Service type of "None" represent planned investments for which a specific Distribution Service classification was not assigned at the time of reporting. In some cases, the Distribution Service type information was not available when the reporting dataset was developed. In other cases, the observed violation that supported the planned investment in a prior planning cycle was no longer present, resulting in the investment not being associated with a specific Distribution Service category at the time of reporting.

Accordingly, these planned investments are included in the overall planned investment totals but are reported with a Distribution Service type of "None" because they were not assigned to a specific Distribution Service category in the reporting dataset.