2025-2026 Transmission Planning Process Unified Planning Assumptions And Study Plan

DRAFT

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1. Introduction

As set forth in Section 24 of the California ISO tariff on the Transmission Planning Process and in the Transmission Planning Process (TPP) Business Practice Manual (BPM), the TPP is conducted in three phases. This document is being developed as part of the first phase of the TPP, which entails the development of the unified planning assumptions and the technical studies to be conducted as part of the current planning cycle. In accordance with revisions to the TPP that were approved by FERC in December 2010, this first phase also includes specification of the public policy objectives the CAISO will adopt as the basis for identifying policy-driven transmission elements in Phase 2 of the TPP that will be an input to the comprehensive planning studies and transmission plan developed during Phase 2. Phase 3 will take place after the approval of the plan by the CAISO Board if projects eligible for competitive solicitation were approved by the Board at the end of Phase 2. If you would like to learn more about the CAISO's TPP, please go to:

- Section 24 of the California ISO tariff located at: http://www.caiso.com/rules/Pages/Regulatory/Default.aspx
- Transmission Planning Process BPM at: http://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx

The objectives of the unified planning assumptions and study plan are to clearly articulate the goals and assumptions for the various public policy and technical studies to be performed as part of Phase 2 of the TPP cycle. These goals and assumptions will in turn form the basis for CAISO approval of specific transmission elements and projects identified in the 2025-2026 comprehensive transmission plan at the end of Phase 2. The CAISO intends to continue updating the High Voltage TAC model for inclusion in the final draft transmission plan, as it has in the past. An opportunity to review the previous year's model for comments will be provided during the year, and has not been scheduled at this time.

The CAISO has collaboratively worked with the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) to align the planning assumptions between the CAISO's TPP and the CPUC's Integrated Resource Plan (IRP) process, as well as the demand forecast assumptions embodied in the 2024 IEPR adopted by the CEC on January 21st, 2025[1].

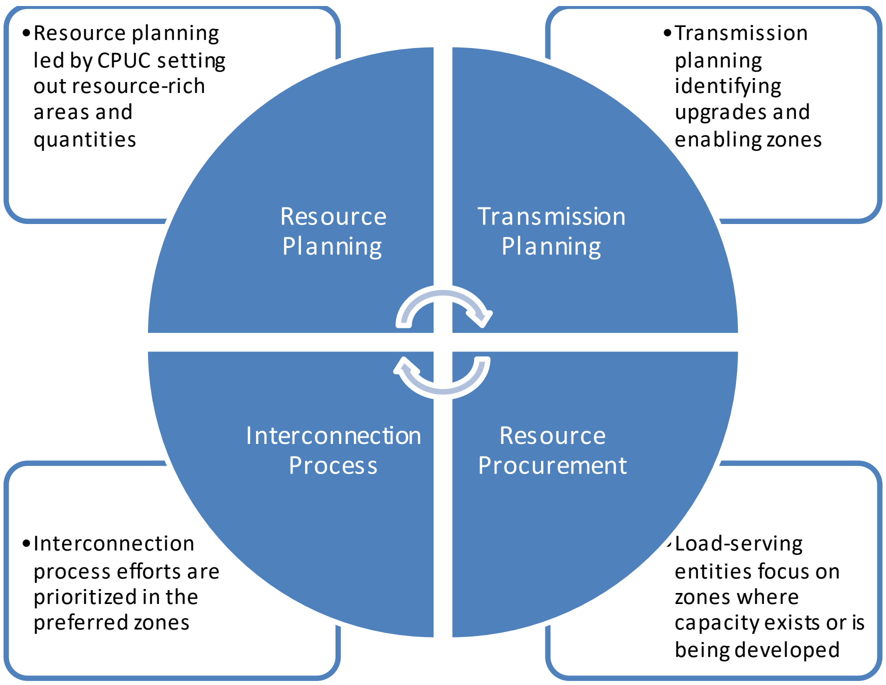
As set out in the MOU, expectations are that the CPUC[2] will continue to provide resource planning information to the ISO as it did for this transmission planning cycle. The ISO will develop a final transmission plan, initiate the transmission projects and communicate to the electricity industry specific geographic zones that are being targeted for transmission projects along with the capacity being made available in those zones. The CPUC will in turn provide

[1] https://www.energy.ca.gov/data-reports/reports/2024-integrated-energy-policy-report-update/2024-iepr-workshops-notices-and-0

[2] In addition to the needs of the jurisdictional load serving entities in the ISO's footprint, the CPUC currently works to include the needs of the publicly owned utilities and other non-CPUC-jurisdictional utilities in its resource planning efforts for the ISO balancing authority area, and this is an issue that will be receiving additional attention in this planning cycles to ensure the needs of these parties are being addressed.

clear direction to load-serving entities to focus their energy procurement in those key transmission zones, in alignment with the transmission plan.

To bring this more coordinated approach full circle, the ISO will also give priority to interconnection requests located within those same zones in its generation interconnection process.



1.1 Overview of 2025-2026 Stakeholder Process Activities and Communications

This section presents general information regarding stakeholder activities and communications that will occur during this planning cycle.

1.1.1 Stakeholder Meetings and Market Notices

During each planning cycle, the CAISO will conduct at least four stakeholder meetings to present and acquire stakeholder input on the current planning effort. These stakeholder meetings are scheduled and designed around major activities in Phase 1 and Phase 2 of the transmission planning process. Additional meetings for each stage may be scheduled as needed. These meetings provide an opportunity for the CAISO to have a dialogue with the stakeholders regarding planning activities and to establish the foundation upon which stakeholders may comment and provide other necessary input at each stage of the TPP.

The current schedule for all three phases of the 2025-2026 transmission planning process is provided in Table 1.1-1. Should this schedule change or other aspects of current transmission planning process require revision, the CAISO will notify stakeholders through a CAISO market notice which will provide stakeholders information about revisions that have been made. As such, the CAISO encourages interested entities to register to receive transmission planning related market notices. To do so, go to the following to submit the Market Notice Subscription Form:

https://www.caiso.com/subscriptions

Table 1.1-1: Current Schedule for the 2025-2026 planning cycle

Phase	No	Due Date	2025-2026 Activity
Phase 1	1	December 30, 2024	The CAISO sends a letter to neighboring balancing authorities, sub-regional, regional planning groups requesting planning data and related information to be considered in the development of the Study Plan.
	2	December 30, 2024	The CAISO issues a market notice announcing a thirty-day comment period requesting demand response assumptions and generation or other non-transmission alternatives to be considered in the Unified Planning Assumptions.
	3	January 30, 2025	PTO's, neighboring balancing authorities and regional/sub-regional planning groups provide CAISO the information requested No.1 above.
	4	January 30, 2025	Stakeholders provide CAISO the information requested No.2 above.
	5	February 19, 2025	The CAISO develops the draft Study Plan and posts it on its website
	6	February 26, 2025	The CAISO hosts public stakeholder meeting #1 to discuss the contents in the Study Plan with stakeholders
	7	February 26 – March 12, 2025	Comment period for stakeholders to submit comments on the public stakeholder meeting #1 material and for interested parties to submit Economic Planning Study Requests and Maximum Import Capability Expansion Requests to the CAISO
	8	March 24, 2025	Inter-regional Coordination Meeting between the three Western Planning Regions (CAISO, NorthernGrid, WestConnect)
	9	April 30, 2025	The CAISO specifies a provisional list of high priority economic planning studies, finalizes the Study Plan and posts it on the public website
Phase 2	10	August 15, 2025	The CAISO posts preliminary reliability study results and mitigation solutions
	11	August 15, 2025	Request Window opens
	12	August 29, 2025	The CAISO will post base scenario base cases for each planning area used in the reliability assessment
	13	September 15, 2025	PTO's submit reliability projects to the CAISO
	14	September 24-25, 2025	The CAISO hosts public stakeholder meeting #2 to discuss the reliability study results, PTO's reliability projects, and the Conceptual Statewide Plan with stakeholders

Phase	No	Due Date	2025-2026 Activity
	15	September 25-October 9, 2025	Comment period for stakeholders to submit comments on the public stakeholder meeting #2 material[3]
	16	October 15, 2025	Request Window closes
	17	October 31, 2025	The CAISO post final reliability study results
	18	November 17, 2025	The CAISO posts the preliminary assessment of the policy driven & economic planning study results and the projects recommended as being needed that are less than $50 million.
	19	November 19, 2025	The CAISO hosts public stakeholder meeting #3 to present the preliminary assessment of the policy driven & economic planning study results and brief stakeholders on the projects recommended as being needed that are less than $50 million.
	20	November 19 – December 5, 2025	Comment period for stakeholders to submit comments on the public stakeholder meeting #3 material
	21	December 18, 2025	The CAISO Board of Governors meeting provides opportunity for stakeholder comments directly to Board of Governors.
	22	March 31, 2026	The CAISO posts the draft Transmission Plan on the public website
	23	April 15, 2026	The CAISO hosts public stakeholder meeting #4 to discuss the transmission project approval recommendations, identified transmission elements, and the content of the Transmission Plan
	24	April 15 – April 29, 2026	Comment period for stakeholders to submit comments on the public stakeholder meeting #4 material
	25	May, 2026	The CAISO finalizes the Transmission Plan and presents it to the CAISO Board of Governors for approval
	26	May 29, 2026	The CAISO posts the Final Board-approved Transmission Plan on its site
Phase 3	27[4]	June 1, 2026	If applicable, the CAISO will initiate the process to solicit proposals to finance, construct, and own elements identified in the Transmission Plan eligible for competitive solicitation

[3] The CAISO will target responses to comments ideally within three weeks of the close of comment periods, and no later than the next public stakeholder event relating to the Transmission Plan.

[4] The schedule for Phase 3 will be updated and available to stakeholders at a later date.

1.1.2 Responses to CAISO's data request

The CAISO received the following responses to the Phase 1 Data Request:

- California Department of Water Resources (CDWR) have clarified the Long-Term outage schedule, system topology, breaker ratings, and spare equipment strategy. In addition CDWR has provided an updated contingency list for P1, P4, P7, and extreme events.
- Hetch Hetchy Water & Power (HHWP) has provided change files which include minor updates to the HHWP system, generation seasonal dispatch for 2025-2040, as well as updated contingency files and supporting information.
- Imperial Irrigation District (IID) provided up to date outage and RAS files.
- LSPower provided an updated set of steady state and transient stability contingency lists for outages involing DesertLink's Harry Allen-Eldorado (HAE) facilities and clarified there are no planned outages.
- NextEra provided models for TransBay cable HVDC, Suncrest SVC, Imperial Valley – North of Songs, and North Gila – Imperial Valley. It has also been clarified that there are no planned outages, no generation interconnections, and the transmission contingencies are unchanged.
- Pasadena Water & Power (PWP) has verified there are no planned outages without a spare to be considered for this planning cycle.
- Silicon Valley Power (SVP) has provided load forecast files and network change files for 2025-2040. SVP clarified that the files provided are based on the 2024 base PSLF model received from PG&E.
- Transmission Agency of Northern California (TANC) indicated that reliability planning data (important for the reliability planning assessments as required by the NERC TPL001-5) is available through WECC and that TANC does not have any additional reliability planning data for the CAISO to consider in the 2025-2026 Transmission Planning Process. Additional comments were provided related to planning information requested.
- Turlock Irrigation District (TID) has provided transmission contingency files.

The below listed entities have provided requested data from Non-CPUC Jurisdictional Integrated Resource Plans (IRP's) to be included in this years transmission planning process,

- City of Anaheim
- City of Colton
- City of Pasadena

- City of Riverside
- City of Vernon
- NCPA
- Silcon Valley Power
- VEA

1.2 Stakeholder Comments

The CAISO will provide stakeholders with an opportunity to comment on all meetings and posted materials. Stakeholders are requested to submit comments within two weeks following the stakeholder meetings. The CAISO will post these comments on the CAISO Website. The CAISO will target responses no later than the next public stakeholder event relating to the Transmission Plan.

1.3 Availability of Information

The CAISO website is the central place for public and non-public information. For public information, the main page for documents related to 2025-2026 transmission planning cycle is the "Transmission Planning" section located at https://www.caiso.com/generation-transmission/transmission/transmission-planning on the CAISO website.

Confidential or otherwise restricted data, such as Critical Energy Infrastructure Information (CEII) is stored on the CAISO secure transmission planning webpage located on the market participant portal at https://mpp.caiso.com/Pages/Default.aspx. In order to gain access to this secured website, each individual must have a Non-Disclosure Agreement (NDA) executed with the CAISO.

The procedures governing access to different classes of protected information is set forth in Section 9.2 of the Transmission Planning BPM (BPM). As indicated in that section, access to specified information depends on whether a requesting entity meets certain criteria set forth in the CAISO tariff. The NDA application and instructions are available on the CAISO website at https://caiso.com/generation-transmission/transmission/transmission-planning#accessing-data under the *Accessing transmission data* heading.

2. Reliability Assessments

The CAISO will analyze the need for transmission upgrades and additions in accordance with NERC Standards and WECC/CAISO reliability criteria. Reliability assessments are conducted annually to ensure that performance of the system under the CAISO controlled grid will meet or exceed the applicable reliability standards. The term "Reliability Assessments" encompasses several technical studies such as power flow, transient stability, and voltage stability studies. The basic assumptions that will be used in the reliability assessments are described in sections 2.1-2.14. Generally, these include the scenarios being studied, assumptions on the modeling of major components in power systems (such as demand, generation, transmission network topology, and imports), contingencies to be evaluated, and reliability standards to be used to measure system performance, and software or analytical tools.

2.1 Reliability Standards and Criteria

The 2025-2026 transmission plan will span a 15-year planning horizon and will be conducted to ensure the CAISO-controlled grid is in compliance with the North American Electric Reliability Corporation (NERC) standards, WECC regional criteria, and CAISO planning standards across the 2025-2040 planning horizon.

2.1.1 NERC Reliability Standards

The CAISO will analyze the need for transmission upgrades and additions in accordance with NERC reliability standards, which set forth criteria for system performance requirements that must be met under a varied but specific set of operating conditions. The following NERC reliability standards are applicable to the CAISO as a registered NERC planning authority and are the primary driver of the need for reliability upgrades

TPL-001-5.1[5]: Transmission System Planning Performance Requirements; and

NUC-001-4 Nuclear Plant Interface Coordination.[6]

2.1.2 WECC Regional Criteria

The WECC System Performance TPL-001-WECC-CRT-4[7] Regional Criteria are applicable to the CAISO as a Planning Coordinator and set forth planning criterion for near-term and long-term transmission planning within the WECC Interconnection.

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[5] TPL-001-5 modified Category P5 single point of failure & R2.4.5 requirements will be implemented based on the TPL-001-5 Implementation plan dates.

[6] Analysis of Extreme Events or NUC-001 are not included within the Transmission Plan unless these requirements drive the need for mitigation plans to be developed

[7] https://www.wecc.org/sites/default/files/documents/standards/2024/TPL-001-WECC-CRT-4.pdf

2.1.3 California ISO Planning Standards

The California ISO Planning Standards specify the grid planning criteria to be used in the planning of CAISO transmission facilities.[8] These standards cover the following:

- Address specifics not covered in the NERC reliability standards and WECC regional criteria;
- Provide interpretations of the NERC reliability standards and WECC regional criteria specific to the CAISO-controlled grid; and,
- Identify whether specific criteria should be adopted that are more stringent than the NERC standards or WECC regional criteria.

2.1.4 Interim Supplemental Criteria due to NERC FAC-014-3 Standard

Requirement R6 of NERC FAC-014-3 Standard requires the ISO to implement a documented process to use Facility Ratings, System steady-state voltage limits and stability criteria in its Planning Assessment of Near-Term Transmission Planning Horizon that are equally limiting or more limiting than the criteria for Facility Ratings, System Voltage Limits and stability described in its respective Reliability Coordinator's SOL methodology. The ISO is incorporating the criteria described in this section of the study plan as an interim measure to address criteria included in the latest RC West SOL Methodology[9], that are not explicitly documented in NERC, WECC and ISO planning standards and criteria. The ISO intends to incorporate these criteria in the ISO Planning Standards following a stakeholder process and Board approval.

Facility Rating Criteria

The ISO will apply the following facility ratings criteria, which are not new but are not appropriately documented.

- Normal Ratings as defined in the NERC Glossary that are valid for unlimited duration shall be used under system normal or P0 planning conditions.
- Emergency Ratings as defined in the NERC Glossary that are valid for a finite duration may be used under contingency conditions provided the ratings are valid for a time duration of 30 minutes or more. This is to ensure system operators have sufficient time to take the corrective action needed to address the impact of a contingency event and prepare for the next contingency.
- If duration limited resources such as energy storage or demand response are relied upon to mitigate the impact of contingencies on the ability to serve forecast load, longer duration emergency ratings or normal ratings may be used taking into account the duration limitation of the resource and the hourly profile of the load.

[8] https://www.caiso.com/Documents/ISO-Planning-Standards-Effective-Feb22023.pdf

[9] https://www.caiso.com/Documents/RC0610.pdf

- Facility ratings provided by RC West will be used if they are more limiting than those provided in the planning models unless there is an approved project that increases the ratings or a documented technical rationale is provided for using the less limiting ratings.

Additions to the ISO Voltage Standard

The system steady state voltage limit requirements described below that are included in RC West's SOL Methodology will be applied in addition to the ISO Voltage Standard that is a part of the ISO Planning Standards:

- Voltage limits must respect facility voltage ratings.
- Voltage limits must enable reliable BES operations.
- System voltage limits must not conflict with relay trip settings for under voltage load shedding schemes (UVLS) and BES facilities or prevent the operation of protection systems.
- System voltage limits provided by RC West will be used if they are more limiting than the the limit provided in the ISO planning Standards there is an approved project that increases the voltage limits or a documented technical rationale is provided for using the less limiting limits.

Stability criteria

The stability criteria from RC West's SOL Methodology below will be applied in the planning assessment in addition to stability requirements described in NERC and WECC Planning Standards:

- Islands formed during controlled separation shall remain stable.
- Planning contingency events shall not lead to frequency decline or swings in the interconnected system that could trigger the action of Under Frequency Load Shedding (UFLS) schemes.

Criteria for identifying potential cascading and uncontrolled

The ISO has established the threshold criteria for excessive loading below that is based on the WECC criteria with some modification. A facility should be flagged for further evaluation of cascading and uncontrolled separation if the facility loading exceeds the lesser of:

- The facility's protection relay trip setting, and
- 125 percent of the facility's highest rating defined for a duration of 30 minutes or more.

A facility loaded above the excessive loading threshold is open-circuited during cascading analysis to account for the potential for removal of the facility from service due to relay action, equipment failure, faults caused by excessive sagging, etc. The use of facility ratings defined for a duration of at least 30 minutes is to align the criteria with the facility rating criteria described above. If the excessively overloaded facility is a series capacitor on a transmission line, the series capacitor should be short-circuited (bypassed) rather than opened-circuited unless specific information is available.

The ISO uses 1000 MW load impact threshold to differentiate situations where the impact of excessive loading is limited to a single facility or a local area from those situations where the successive loss of transmission facilities due to excessive loading could lead to adverse reliability impacts on a large portion of the BES. The load impact threshold represents an upper bound for load loss regardless of demonstrated containment, but excludes the loss of load due to the intended action of RAS/SPS.

500 kV Path Planning Considerations

500 kV paths in the CAISO system are bridges between adjacent systems used to wheel power and warrant additional consideration during planning. These paths are operated in real time within nomograms to prevent next contingency violations and are subject to immediate post-contingency redispatch. These paths have remedial action schemes that also help to mitigate post contingency effects. Reliability planning for these lines reflects operational procedures and allows for redispatch between contingencies for P6 events so long as post-contingency and post RAS flow does not reach a limit at which cascading becomes an issue.

2.2 Frequency of the study

The reliability assessments are performed annually as part of the CAISO's Transmission Planning Process (TPP).

2.2.1 Use of past studies

The annual TPP Reliability Assessment is performed mainly in accordance with study requirements set forth in NERC TPL-001-5.1 Standard. Within the Standard, the Requirement R2.6 allows for use of past studies to support the planning assessment. Similar to the previous TPP cycle, the CAISO will evaluate areas known to have no major changes compared to assumptions made in prior planning cycles for potential use of past studies.

On a high level, the process will include three major steps. 1) Data collection, 2) evaluation of data for extent of change and 3) drawing conclusion based on the extent of change in data and considering other area specific factors.

2.2.2 Study Horizon and Years

The studies that comply with TPL-001-5.1 will be conducted for both the near-term[10] (2027-2030) and longer-term[11] (2030-2040) per the requirements of the reliability standards.

Within the identified near and longer-term study horizons the CAISO will be conducting detailed analysis on years 2027, 2030 and 2035. Additionally, for long-term scenario, 2040 will also be studied. If in the analysis it is determined that additional years are required to be assessed the CAISO will consider conducting studies on these years or utilize past studies[12] in the areas as appropriate.

[10] System peak load for either year one or year two, and for year five as well as system off-peak load for one of the five years.

[11] System peak load conditions for one of the years and the rationale for why that year was selected.

[12] Past studies may be used to support the Planning Assessment if they meet the following requirements:
1. For steady state, short circuit, or stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. 2. For steady state, short circuit, or stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.3 Study Areas

The reliability assessments will be performed on the bulk system (north and south) as well as the local areas under the CAISO controlled grid. Figure 2.3-1 shows the approximate geographical locations of these study areas. The full-loop power flow base cases that model the entire Western Interconnection will be used in all cases. These 18 study areas are shown below.

- Northern California (bulk) system – 500 kV facilities and selected 230 kV facilities in the PG&E system
- PG&E Local Areas:
    - Humboldt area;
    - North Coast and North Bay areas;
    - North Valley area;
    - Central Valley area;
    - Greater Bay area;
    - Greater Fresno area;
    - Kern Area; and
    - Central Coast and Los Padres areas.
- Southern California (bulk) system[13] – 500 kV facilities in the SCE and SDG&E areas and the 230 kV facilities that interconnect the two areas.
- SCE local areas:
    - Tehachapi and Big Creek Corridor;
    - North of Lugo area;
    - East of Lugo area;
    - Eastern area; and
    - Metro area.
- San Diego Gas & Electric (SDG&E) area
- Valley Electric Association (VEA) area[14]
- CAISO overall bulk system

[13] SunZia and TransWest Express (TWE) are included within the Southern California bulk system for assessment in the 2025-2026 Transmission Planning Process

[14] GridLiance West, LLC (GLW) owns 230kV facilities in VEA's service territory. VEA operates and maintains GLW's 230kV facilities. In this report, VEA normally refers to VEA's service territory. When identifying specific projects or specific PTOs, VEA or GLW will be used depending upon who owns the facilities specified or the PTO referenced.

Figure 2.3-1: Approximated geographical locations of the study areas

2.4 Transmission Assumptions

2.4.1 Transmission Projects

The transmission projects that the CAISO has approved will be modeled in the study. This includes existing transmission projects that have been in service and future transmission projects that have received CAISO approval in the 2024-2025 or earlier CAISO transmission plans. Currently, the CAISO anticipates the 2024-2025 transmission plan will be presented to the CAISO board of governors for approval in May 2025. Projects put on hold will not be modeled in the starting base case.

2.4.2 Reactive Resources

The study models the existing and new reactive power resources in the base cases to ensure that realistic reactive support capability will be included in the study. These include generators, capacitors, static var compensators (SVCs), synchronous condensers and other devices. In addition, Table A5-1 of Appendix A provides a list of key existing reactive power resources that will be modeled in the studies. For the complete list of these resources, please refer to the base cases which are available through the CAISO secured website.

2.4.3 Protection System

To help ensure reliable operations, many Remedial Action Schemes (RAS), Protection Systems, safety nets, Under-voltage Load Shedding (UVLS) and Under-frequency Load Shedding (UFLS) schemes have been installed in some areas. Typically, these systems shed load, trip generation, and/or re-configure system by strategically operating circuit breakers under select contingencies or system conditions after detecting overloads, low voltages or low frequency. The major new and existing RAS, safety nets, and UVLS that will be included in the study are listed in section A5 of Appendix A. Per WECC's RAS modeling initiative, the CAISO has been modeling RAS in power flow studies for some areas in previous planning cycles as they were made available by the PTOs. The CAISO will continue the effort of modeling RAS in this planning cycle working with the PTOs with a target to model all RAS in the CAISO controlled grid.

2.4.4 Control Devices

Expected automatic operation of existing and planned devices will be modeled in the studies. These control devices include:

- All shunt capacitors
- Dynamic reactive supports such as static var compensators and synchronous condensers at several locations such as Potrero, Newark, Rector, Devers, Santiago, Suncrest, Miguel, San Luis Rey, San Onofre, and Talega substations
- Load tap changing transformers
- DC transmission lines such as PDCI, IPPDC, and Trans Bay Cable Projects
- Imperial Valley phase shifting transformers

2.5 Load Forecast Assumptions

2.5.1 Energy and Demand Forecast

The assessment will utilize the 2024 California Energy Demand Update (CEDU) Forecast 2024-2040 adopted by the California Energy Commission (CEC) on January 21st, 2025[15] using the corresponding LSE and BA Table Mid Baseline spreadsheet with applicable Additional Achievable Energy Efficiency (AAEE), Additional Achievable Fuel Substitution (AAFS), Additional Achievable Transportation Electrification (AATE) and DataCenter(DC) load modifiers. The 2024 CEDU Forecast also includes 8760-hourly demand forecasts for the three major Investor Owned Utility (IOU) TAC areas as well as for the entire CAISO.

The CAISO engaged in collaborative discussion with CEC and CPUC on how to consistently account for reduced energy demand from energy efficiency in the planning and procurement processes. As typically performed in the previous transmission planning process cycles, the previous 2024 IEPR final report[16], adopted on January 21st, 2025 based on the IEPR report and in consultation with the CPUC and the CAISO, recommends using the Mid Demand-AAEE Scenario 3, AAFS Scenario 3 and AATE Scenario 3 for system-wide and flexibility studies for the CPUC LTPP and CAISO TPP studies. However, for local area studies, because of the local nature of reliability needs and the difficulty of forecasting load, AAEE, AAFS and AATE at specific locations and estimating their daily load-shape impacts, using the Mid Demand-AAEE Scenario 2, AAFS Scenario 4 and AATE Scenario 3 is recommended. In addition, new to the 2024 IEPR, data center load forecast has been moved from other adjustment and is included as a distinct load modifier.

The CEC forecast information is available on the CEC website at:

https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2024-integrated-energy-policy-report

In general, the following are guidelines on how load forecasts are used for each study area.

- The 1-in-10 weather year, mid demand baseline case local reliability scenario (with AAEE Scenario 2, AAFS Scenario 4 and AATE Scenario 3) load forecasts will be used in PG&E, SCE, SDG&E, and VEA local area studies including the studies for the local capacity requirement (LCR) areas.
- The 1-in-5 weather year, mid demand baseline planning (with AAEE Scenario 3, AAFS Scenario 3 and AATE Scenario 3) load forecasts will be used for system studies
- The 1-in-2 weather year, mid demand baseline planning (with AAEE Scenario 3, AAFS Scenario 3 and AATE Scenario 3) load forecasts will be used for production cost study.

15 https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2024-integrated-energy-policy-report

16 This section is to be updated when the 2024 IEPR final report is made available.

Valley Electric Association, Inc. (VEA) joined the California ISO control area in 2013. While most customers of the load serving entity reside in Nevada, a relatively small portion of VEA's service territory extends into parts of California. As such, the Energy Commission routinely develops forecasts of electricity sales to be used in assessing statewide progress toward meeting California's Renewable Portfolio Standard, as well as forecasts of VEA's peak load to inform the California ISO's transmission planning process.

To ensure the VEA load forecast has incorporated relevant information, VEA may provide local data to the Energy Commission and Energy Commission staff committed to a more holistic approach to forecasting VEA load growth in response. The following information by customer sector may be provided by VEA to the CEC for this purpose: historic sales, historic (and projected if available) electricity rates, historic (and projected if available) installed capacity of BTM resources by technology, forecasts of sales and peak demand forecasts (including documentation of forecast methods), and supporting documentation for any significant incremental loads.

The CEC staff typically uses econometric methods to prepare electricity sales and peak demand forecasts for the VEA service territory in its entirety. Additionally, the CEC staff may review documentation of new service requests provided by VEA and determines whether an incremental adjustment to non-residential sales projections would be appropriate to account for additional planned electricity demand that would otherwise not be captured in the forecast using econometric methods.

Single Managed Forecast Set for Electricity Planning

The following list describes the current agreement among the lead staff of the joint agencies and California ISO:

1. **CPUC IRP Reference System Plan, Preferred System Plan, and California ISO TPP economic studies:**
    - Baseline annual energy and annual peak demand
    - Data center mid case
    - BTM DG mid case
    - AAEE Scenario 3 annual energy and peak demand
    - AAFS Scenario 3 annual energy and peak demand
    - AATE Scenario 3 annual energy and peak demand
    - 1-year-in-2 peak event weather conditions
2. **California ISO TPP policy studies and bulk system studies:**
    - Baseline annual energy and annual peak demand

- Data center mid case
- BTM DG mid case
- AAEE Scenario 3 annual energy and peak demand
- AAFS Scenario 3 annual energy and peak demand
- AATE Scenario 3 annual energy and peak demand
- 1-year-in-5 peak event weather conditions
- Planning Forecast hourly loads
- CEC staff allocations of AAEE, AAFS, AATE and DC to load buses used in transmission planning related studies

3. **California ISO TPP local reliability studies and local capacity technical studies:**
   - Baseline annual energy and annual peak demand
   - Data center high case
   - BTM DG low case
   - AAEE Scenario 2 annual energy and peak demand
   - AAFS Scenario 4 annual energy and peak demand
   - AATE Scenario 3 annual energy and peak demand
   - 1-year-in-10 peak event weather conditions
   - CEC staff allocations of AAEE, AAFS, AATE and DC to load buses used in transmission planning related studies

2.5.2 Methodologies to Derive Bus Level Forecast

Since load forecasts from the CEC are generally provided for a larger area, these load forecasts do not contain bus-level load forecasts which are necessary for reliability assessment. Consequently, the augmented local area load forecasts developed by the participating transmission owners (PTOs) will also be used where the forecast from the CEC does not provide detailed bus-level load forecasts. Descriptions of the methodologies used by each of the PTOs to derive bus-level load forecasts using CEC data as a starting point are described below.

2.5.2.1 CEC Staff Methodology for Load Modifier Allocation to Load Busses

Power flow modeling requires future year load forecasts at the level of transmission busses as one of the key inputs. The CAISO approach to this is more complex than for many other users of power flow models, because of the increasing emphasis on inclusion of energy policy impacts and multiple entities contributing portions of the overall set of load bus inputs.

Three basic elements are needed:

1. The CEC demand forecast of TAC area loads, at both CAISO-wide coincident basis and an individual TAC-area non-coincident basis, for each of several levels of peak weather severity is the control total.
2. The CEC provides an assessment of individual transmission load bus impacts resulting from its assessment of three types of load modifiers that are included in the determination of system peak hour loads. The three types of policy-based load modifiers are:
    a. Utility energy efficiency programs, California or federal building and appliance standards, and other federal, state, or local programs;
    b. Utility program to incent substitution of electricity to replace combustion fuels (natural gas and propane) in buildings and industry;
    c. Regulations of California Air Resources Board emission reduction mandates as well as similar mandates of local air quality management districts
3. IOU projections of CEC system-level or TAC-level load by load bus without the impacts assessed the CEC for load modifiers as described in item 2b above.

The CAISO and IOUs work together to populate the load portion of the power flow base cases guided by the above approach.

The detailed approach that the CEC uses for each of the three categories of load modifiers are discussed in the two sections below. These descriptions are accurate for the 2023-24 TPP cycle (using CEC 2022 IEPR demand forecasts), but limited revisions will be undertaken for the 2024-25 TPP cycle which are described in summary fashion at the end of each section.

<u>Additional Achievable Energy Efficiency (AAEE) and Fuel Substitution (AAFS) Load from IEPR 2024</u>

The load bus analysis that the CEC conducts each year for CAISO allocates the CEC's AAEE and AAFS load modifier forecasts to IOU and POU substations and WECC busbars. The CEC sends CAISO two excel workbooks for this analysis, with the first workbook containing load bus results for coincident CAISO peak load, and the second workbook containing load bus results for non-coincident Utility peak load. Coincident peak load bus results contain peak hour MW AAEE and AAFS results that are reported at the same peak dates (month, day, and hour) for each Utility, and can only vary by IEPR forecast scenario and year. Non-coincident peak load bus results contain peak hour MW AAEE and AAFS results that can have varying peak dates (month, day, and hour) for each Utility, IEPR forecast scenario, and year.

The first stage of the load bus analysis is to work in conjunction with CPUC to send out a data request to the IOUs to receive 24 hours of MW load that was observed by each Utility for two peak dates. The first date we request is for the day that each Utility's system peaked in the previous year, which will change amongst each IOU, while the second date is for the day that the CAISO system peaked in the previous year. MW loads from the IOUs are reported by the transmission planning WECC busbars that the IOUs and CAISO agree on for power flow modeling purposes and are disaggregated by eight customers sectors. These sectors include residential, commercial, industrial, mining/extraction, ag/pumping, transportation/communication/utility, streetlighting and other. Three customer sectors (transportation/communication/utility, streetlighting and other) are summed up with the Commercial sector to aggregate the IOU MW load to just five customer sectors used in the load bus analysis. Further geographic granularity for these WECC busbars is requested by asking for a list of ZIP codes that detail where end-use customers are connected to a given WECC bus or substation, and the ZIP code locations of each substation.

The second stage of the load bus analysis is to create groups within each AAEE and AAFS scenario that aggregates the load modifier annual energy projections into groupings of the individual programs that were modeled at the annual energy level. This step sets the stage for allocating each group according to different distribution shares across the whole set of load busses with each utility area. For the load bus analysis that was delivered to CAISO in March of 2023, the CEC's AAEE and AAFS scenarios were aggregated into 5 major programmatic groups. The first three groups of AAEE and AAFS results dealt primarily with new construction oriented programs/standards (such as Title 24 and Local Government Ordinances) that have a greater level of geographic granularity than the other modeled programs. The fourth group of AAEE and AAFS results contains programs that have no clear distinction that splits the impacts between new construction or existing/retrofit building improvements and are expected to be distributed according to existing customer sector loads, unlike groups 1-3. The fifth and final group of AAEE and AAFS results separate out the fuel substitution impacts of CARB's zero emission space and water heater measure from the 2022 SIP Strategy that is modeled using CEC's Fuel Substitution Scenario Analysis Tool (FSSAT).

After determining which programs modeled in AAEE and AAFS (and now also inclusive of FSSAT) are assigned to the 5 defined groups, the annual load modifiers are run through the CEC's energy efficiency and fuel substitution hourly tools. Hourly AAEE and AAFS results get produced for each group and for each Electric Utility to be used in the load bus analysis. The electric utilities for which the hourly results are reported include PGE, SCE, and SDGE for the IOUs (at the TAC level), and SMUD, LADWP, NCNC (exclusive of SMUD), IID, BUGL, NorCal Other, and SoCal Other for the POUs. NorCal Other accounts for the smaller POUs in northern California, while SoCal Other accounts for the smaller POUs in southern California. Once these hourly AAEE and AAFS hourly forecasts have been created, they are brought into the CEC's load bus analysis R script to be reformatted and to remove any previous year's load modifier impacts from the forecast.

The third stage of the load bus analysis is to determine which month, day, and 24 hour period of MW load impacts to use from the AAEE and AAFS hourly results for each year, utility, and IEPR forecast scenario (planning forecast and local reliability scenario). Hourly Demand Forecasts for the current IEPR cycle are downloaded from the CEC's website for the CAISO system and the three TAC area IOUs for a total of eight files (four for the planning forecast and four for the local reliability scenario). The two CAISO system hourly demand forecast files are used for the coincident CAISO peak load bus analysis, while the six TAC area IOU hourly demand forecast files are used for the non-coincident peak load bus analysis. Each forecast file is brought into the load bus analysis R script to determine, for each forecast year, the month, day, and hour the managed net forecast peaks for the CAISO system and each TAC area IOU in the planning scenario and local reliability scenario.

For the coincident peak load bus analysis, the yearly system peak dates found from the CAISO system hourly demand forecast are used to filter the hourly AAEE and AAFS results to a 24 hour profile of MW impacts. This is done for each forecast year, building sector, and utility. This filtering process leaves the AAEE and AAFS scenarios that are part of either the planning forecast or local reliability scenario. As mentioned above, these coincident peak dates do not change amongst the IOUs or POUs, so there would only be a variation in the peak dates between the forecast years and the two forecast scenarios.

The non-coincident peak load bus analysis follows the same filtering process as the coincident peak analysis above, but it uses the yearly peak dates found from the individual PGE, SCE, and SDGE TAC area hourly demand forecast files. It also uses different peak dates for each forecast year and each IOU. For SMUD, NCNC, and NorCal Other, the PGE TAC peak hour for each forecast year determines the 24-hour day to assign the AAEE and AAFS impacts. This approach follows for LADWP, IID, BUGL, and SoCal Other, using the SCE TAC peak hour for each forecast year.

The fourth stage of the load bus analysis is to create the allocation shares that will assign the Utility based AAEE and AAFS load modifiers to the IOU and POU WECC busbars. Different IOU allocation shares are used for the various AAEE and AAFS group combinations, while the same POU allocation shares are used for all AAEE and AAFS groups.

For the IOU allocation shares used on the Groups 1-3 AAEE and AAFS load modifiers, both historical and forecasted new construction data from various sources are used. The major data source for these shares is the California new construction residential housing forecast (by County) that comes from Moody's Analytics. A historic new construction forecast for 2015-2020 that is by county and city is then used to disaggregate the county-based Moody's forecast into a county- and city-wide forecast. Finally, to map the WECC busbars and ISO IDs (from the CPUC data request) to the city and county Moody's new construction forecast, a ZIP code to city and county map provided by USPS is used. Shares are then created for each forecast year and IOU by dividing the number of new homes that a WECC busbar and ISO ID combination serve by the total number of homes served by a given Utility. These shares are summed from a city and county level to a utility level of geography for use in the load bus analysis R script.

For the IOU allocation shares used on the groups 4-5 AAEE and AAFS load modifiers, the confidential 24 hour-profiles of MW load data for peak days that were requested from the IOUs is used. Using the MW load data, shares are created for each customer sector and Utility combination by dividing the MW value for each WECC bus and ISO ID combination by the total MW load seen for the chosen sector and Utility. This share creation process is done separately for each of the 24 hour-profiles of MW load data for peak days received from the IOUs and is done once using the Utility peak date MW values and once using the CAISO peak date MW values. In the end, two sets of shares are created for each IOU, with the first set made with the MW load data on the day that the utility peaked and the second set made with the MW load data on the day that the CAISO system peaked. This process allows for the creation of allocation shares that vary by utility, sector, hour of day, and system peak type (CAISO vs Utility), which improves the accuracy of spreading the CEC's hourly AAEE and AAFS load to WECC busses.

The POU allocation shares used on the groups 1-5 AAEE and AAFS load modifiers are created using forecasted MW load data (for a single year) from CAISO's previous year Power Flow Base Case by dividing load bus values by the sum of load bus values by utility. Forecast peak MW data is provided for each WECC Bus in a POU territory at single future year (for the 2022 load bus analysis, this future year was 2027), and then gets split into MW values for Northern vs Southern POUs. After the North vs South split is finished, certain groups of utilities are merged to form a new set of utility names used in the load bus analysis. The three utility names used for the northern POUs are SMUD, NCNC (exclusive of SMUD) and North (all other northern POUs), while the four utility names used for the southern POUs are LADWP, BUGL, IID, and South (all other southern POUs). Using these new utility names, shares are created by dividing the MW load seen at a single WECC bus in each POU territory by the total MW load seen by all the WECC busses in the same POUs territory. Unlike the IOU shares, these shares created for the POUs do not differ by either sector or year. These shares will only vary based on which POU is being processed.

The fifth stage of the load bus analysis is to apply the allocation shares to the AAEE and AAFS peak MW results for the planning forecast and local reliability scenario. The IOU AAEE and AAFS MW loads for groups 1-3 are distributed using the new construction-based shares, while the MW loads for groups 4 and 5 are distributed to the customer sector-based shares created using the confidential load data from the IOUs. For POU AAEE and AAFS peak MW projections, since source data did not provide sector or ZIP level detail, we could not include program groups in the share creation. This meant that the POU MW results for groups 1-5 were applied to the same POU share for each group. Once the IOU and POU AAEE and AAFS peak MW results are allocated to the WECC BUS numbers, Substation names, and ISO IDs, they are split to create two peak forecast datasets, one for the peak hour results, and one for the 24 hours of peak results. In the peak hour results dataset, the AAEE and AAFS values are further split up to separate the coincident peak results from the non-coincident peak results, which will be output into two separate files. The 24 hours of peak day results, however, stay as one output file, and only show coincident and non-coincident results for PGE, SCE, and SDGE service territories, as hourly load data (for the peak day) was not provided by the POUs.

<u>Changes to AAEE and AAFS Load Bus Analysis Process for IEPR 2024</u>

The load bus analysis for the 2024 IEPR is expected to follow the same process for assigning hourly peak MW load for AAEE and AAFS to WECCBUS and substations that was used for the 2023 IEPR load bus analysis. This includes using the same methods for creating the IOU and POU Utility to WECCBUS shares and continuing to split the AAEE and AAFS hourly savings into different groups. To determine which peak dates to provide substation level AAEE and

AAFS hourly results for, CEC staff only looked at coincident and non-coincident summer peak values for the 2023 IEPR load bus analysis. As a result of discussions with CAISO transmission planning staff, for the 2024 IEPR, CEC staff will now expand the analysis to include 24-hour profiles for the dates of coincident and non-coincident peaks for the summer peak hour, the winter peak hour, the winter off peak hour, and the spring off peak hour. By diversifying the seasonal impacts of AAEE and AAFS hourly MW load, a more detailed and nuanced look at the added or removed MW load at substations is possible. CAISO staff expects that by improving its off peak condition assessments using these seasonally differentiated AAEE and AAFS results that this will lead to more accurate power flow modeling results.

Allocation of Additional Achievable Transportation Electrification (AATE) Load

The Transportation load bus allocation begins with determining proportional shares of energy by ZIP codes for light-duty vehicles (LDV) and medium- and heavy-duty vehicles (MDHD) separately. A variety of datasets were used in this assignment of energy to capture different assumptions about the geography of vehicle charging behavior. The following writeup describes the methodologies for assigning shares of transportation-associated electricity demand to ZIP codes for LDV and MDHD respectively, and for subsequently allocating demand to transmission-level substations.

Light Duty Vehicles

For LDV, the energy remains at the forecast zone level, as in the IEPR electricity demand forecast, and is first split up into the following shares to be further disaggregated by different methods. The percentages listed below are the proportional share of statewide energy demand that is then further allocated by each dataset.

For Forecast Zones 0 and 3:

1. Major highway traffic data by ZIP codes – 45%
2. Gasoline retail sales for light-duty vehicle by ZIP codes – 45%
3. DMV vehicle registration data by ZIP codes – 10%

For Forecast Zones 1, 2, 4 through 20:

1. DMV vehicle registration data by ZIP codes – 70%
2. Historical commercial WECC bus loads by ZIP codes – 15%
3. Gasoline retail sales for light-duty vehicle by ZIP codes – 5%
4. DCFC Charger Stations by ZIP codes – 5%
5. Major highway traffic data by ZIP codes – 5%

Each dataset incorporates assumptions about a different type of light-duty vehicle charging. To start, DMV vehicle registration data represented potential at-home charging locations, and historical loads for commercial sector captured potential workplace or other commercial charging. Gasoline retail sales data and known DCFC charger station data were used to represent potential locations of public charging; traffic data for major highways also captured public charging, but with a focus on long distance travel. All of these datasets were used to disaggregate light-duty load in forecast zones 1, 2, and 4 through 20 from forecast zones to ZIP codes. Due to higher gasoline consumption per vehicle and higher traffic per human population density observed in forecast zones 0 and 3, the allocation of energy to ZIP codes for these two zones was concentrated on major highway traffic data and gasoline retail sales data.

Medium and Heavy Duty Vehicles

Once the electricity demand resulting from freight and service trucks in AATE was summed up to the statewide total for MDHD, the following shares of statewide MDHD energy were used to be further disaggregated by different methods. As with the light-duty methodology, the percentages listed below are the proportional share of statewide energy demand that is then further allocated by each dataset.

For freight and service trucks:

1. Freight travel data from California Statewide Travel Demand Model (CSTDM) by ZIP codes – 50%

2. Diesel retail sales by ZIP codes – 25%

3. Diesel retail sales by ZIP codes for which the Army Corps of Engineers' cumulative "hubness" score of 100 or less – 5%

4. Diesel retail sales by ZIP codes for which the Army Corps of Engineers' cumulative "hubness" score of more than 100 – 15%

5. Transportation Refrigeration Unit (TRU) applicable facilities data from CARB – 5%

Each dataset reflects assumptions about different types of medium- and heavy-duty charging. To begin with, the freight movement data from the California Statewide Travel Demand Model (CSTDM) provided origins and destinations for modeled freight movement within the state, capturing a mixture of potential depot and public charging. Also, as a starting point, CARB's dataset on TRU applicable facilities data was incorporated to represent some potential depot charging at facilities that may be likely to have additional charging for refrigeration purposes; future iterations will strive to include more comprehensive data on commercial facilities with freight activity.

Diesel retail sales data provided potential locations of public charging for trucks, and was used both on its own and with further weighting provided by a measure of freight traffic optimization called "hubness." This "hubness" score was developed by the Army Corps of Engineers for the California Transportation Commission (CTC)'s Senate Bill 671 Clean Freight Corridor Efficiency Assessment. The Army Corps of Engineers used real-world traffic datasets to perform an optimization of existing truck service stations as candidate locations for zero-emissions infrastructure that would minimize freight traffic diversion. After performing many runs of the statewide optimization, the number of times a particular census tract appeared in the runs was counted as a metric termed “hubness,” indicating a high degree of suitability for serving as a hub for truck refueling. Certain ZIP codes with higher hubness scores were given additional shares of energy to reflect an assumption that these locations would be more likely to have existing logistical and other trucking services suitable for MDHD charging infrastructure.

For buses, electricity demand is produced by bus category for the IEPR forecast, so the load associated with buses was allocated to ZIP codes by distinct data sources that correlate to each of the four key bus categories:

1. Urban Buses – Bus stock data from CARB’s Innovative Clean Transit inventory by ZIP codes

2. Demand Response Buses – Bus stock data from CARB’s Innovative Clean Transit inventory by ZIP codes

3. School Buses – CARB school bus stock data from 2017-2018 by ZIP codes

4. Shuttle Buses – CARB airport shuttle stock data by ZIP codes

A crucial component of this disaggregation methodology for AATE was the conservation of energy at both the annual level and forecast zone level for LDV and MDHD respectively. In other words, the annual load for LDV was conserved for each year and for each forecast zone, ensuring that this load matches the energy results that were used for the IEPR 2022 electricity demand forecast. This same energy conservation was also performed for MDHD.

Allocation to Substations

After GWh were assigned ZIP codes for LDV and MDHD, the AATE load was then prepared for the peak hours of requested coincident and non-coincident peak days. Since the adopted 2022 IEPR hourly demand forecast files are incremental to 2021, the hourly demand output for AATE was regenerated to be incremental to 2022. A simple subtraction of AATE load in 2022 from all other forecast years would not be sufficient, due to the way that transportation load shapes are applied on an annual basis. This new hourly demand file for AATE, made incremental to 2022, provided the total peak hour MW for LADWP, SMUD, SCE, PGE, and SDGE respectively.

For the three IOUs (SCE, PGE, SDGE), the ZIP code GWh assigned for LDV and MDHD in previous steps was then scaled to the peak hour load shape for the ZIP code’s TAC area, resulting in a peak load for each ZIP code.

A crosswalk of ZIP codes and WECCBUS IDs was used to generate the percent of each ZIP code’s peak load that would then be assigned to a WECCBUS peak load for the hour. For PGE, a further layer of disaggregation was needed to crosswalk to ISO Bus IDs. Notably, staff assumed that substations with that shared the same associated ZIP code would have an equally divided share of the ZIP code peak load. For example, if a ZIP code had three associated substations, each substation would receive a third of the ZIP code peak load. These peak load assignments for each substation (WECCBUS ID) were summed for all ZIP code-level transportation peak loads to an associated substation.

In contrast, since CAISO requested that load allocation to non-IOU planning areas (NCNC, BUGL) and POUs be reported separately, additional energy proportioning for those regions was performed. Annual loads for NCNC and BUGL were derived from Form 1.1c (LSE and BA Planning Forecast, Electricity Deliveries to End Users by Agency (GWh)). Staff then calculated a percent of annual transportation load for each forecast year's peak hour within a TAC and by duty from the IEPR 2022 hourly demand files. Because the CEC does not currently have load shapes specific to NCNC and BUGL, the peak hour's percent of annual load for the nearest TAC area (PGE for NCNC, SCE for BUGL) was applied to the annual loads from Form 1.1c to create a peak hour MW value for LDV and MDHD.

To distinguish energy for POUs within a TAC area, forecasted load data from CAISO's previous year Power Flow Base Case that was available to the CEC for POU substations were used to derive an assumed proportion of TAC area load that belongs to POUs. This proportion of POU load within a TAC area was applied to the total TAC peak load, creating the POU peak load for LDV and MDHD in each forecast year. POUs residing in the SCE TAC were labeled as "South" and POUs residing in the PGE TAC were labelled as "North." With the requested POUs' peak hour loads determined for each forecast year, energy shares of each substation within its POU were used to split the peak hour load to the respective substations.

The final deliverables to the CAISO for AATE load allocation were two workbooks – one for CAISO-wide coincident peaks and one for non-coincident peaks by TAC area – that contained the peak hour transportation-related load impacts for each transmission substation within both IOUs and POUs and for both LDV and MDHD.

Changes to AATE Load Bus Analysis Process for IEPR 2023 and IEPR 2024

In alignment with aforementioned updates to the AAEE and AAFS analyses, the AATE load bus analysis for 2023 IEPR and 2024 IEPR will also expand from only the 24-hour profile of the annual peak day to include 24-hour profiles for the all coincident and non-coincident peak dates for the summer off peak day, winter peak day, winter off peak day, and spring off peak day. This will allow the impacts of seasonality for AATE hourly load to be further analyzed in the CAISO's power flow modeling resultsstudies.

As for key data inputs of the AATE load bus analysis, Throughout a process of collaborative engagement with CPUC and IOUs on the Freight Infrastructure Proposal Planning process development throughout during 2023, CEC staff identified potential improvements to specific data inputs in the AATE methodology for load bus allocation were identified. Although the general flow and framework for AATE load bus analysis will remain the same as in the IEPR 2022 cycle, the specific datasets used for allocating AATE load are subject to change as CEC staff explore new data. Discussions between CPUC, IOUs, and CEC led to the determination that particular attention would be needed for for load busses along key corridors of freight transportation that have high volumes of freight-related travel and for specific locations of interest, such as ports and border crossings. Such load busses should receive increased allocations in comparison to the IEPR 2022 analysis. In addition, CEC staff identified crucial errors in the crosswalk of WECCBUS substations and ZIP codes previously provided for IEPR 2022, which led to potential misallocation of transportation-related loads. These findings have led to the following planned updates for AATE load bus analysis of IEPR 2023 and 2024:

- New data from IOUs
  - Using GIS shapefiles provided by IOUs to create a more accurate mapping of WECCBUS substations to ZIP codes.
  - Analyzing historical load from sub-metered EV chargers provided by IOUs in latest data request.
- Additional methodological improvements from CEC staff
  - Incorporating CARB's Large Entity Reporting data to include more truck fleet bases.
  - Further improvements of LDV DCFC methodscharger datasets
  - Port-specific substation allocationUsing truck traffic volume data along freight corridors
  - Exploring different weights for disaggregation methods by MDHD truck class to capture differences in expected charging behavior

2.5.2.2 Pacific Gas and Electric Service Area

The methodology employed to establish PG&E power flow base case loads involves a comprehensive process that integrates and refines information sourced from the CEC IEPR, transmission and distribution systems and municipal utility forecasts.

PG&E Loads in Power Flow Base Case

The process used to calculate PG&E loads mirrors the methodology from previous studies. It involves determining division loads for the required 1-in-5 heat wave for system study cases or 1-in-10 heat wave for area base cases, along with allocating these division loads to transmission buses. PG&E's load comprises several components: conforming load, nonconforming load, self-generation, station service loads, load modifiers (AAEE, AAFS, and AATE, etc) and MUNI loads. PG&E organizes its service territory into 20 divisions for planning studies. Subsequently, these 20 divisions are combined to form seven planning areas within the service territory.

Determination of Division Loads

The annual division load is determined by summing the previous year division load and the current division load growth. Thus, the key steps are the determination of the initial year division summer peak load and the annual summer peak load growth.

The method for establishing the initial year in the base case development heavily relies on recent recorded data, specifically focusing on daily peak loads and peak temperatures during the summer months from the past 2 to 5 years. These datasets are chosen as the primary database to create initial year summer peak load forecasts. The initial year's summer peak load forecast, serving as the starting point for each division, is determined by calculating both the 1-in-5 and 1-in-10 heat wave summer peak loads specific to each division. This calculation involves referencing the 1-in-5 and 1-in-10 high temperatures particular to each division, which are established based on historical temperature data spanning several decades. To develop these forecasts, a load-temperature correlation is established for each division. This correlation is derived from the analysis of recorded daily peak loads and daily peak temperatures within each division during the summer months. After getting the net starting point for each division, behind-meter-PV (BTM-PV) output at the division peak time is added back to get the gross starting point for the division.

In the system 1-in-5 heat wave load forecast, which is designed for assessing high voltage systems ranging from 230-500 kV, the CEC IEPR (California Energy Commission Integrated Energy Policy Report) 1-in-5 heat wave demand forecast serves as the basis. To make this forecast more reflective of the actual conditions, several adjustments are made by subtracting system loss and adding station service and self-generation loads. The initial year's PG&E division load is obtained by allocating the CEC 1-in-5 heat wave Year 1 forecast to each division using its gross starting point and coincidence factor. Subsequently, the following year's PG&E division load is determined by allocating the load growth indicated in the CEC 1-in-5 forecast to each division, considering the distribution load growth within each division in relation to the overall system load growth.

In the area 1-in-10 load forecast, which is designed for assessing local area networks operating within the voltage range of 60-230 kV, the CEC IEPR (California Energy Commission Integrated Energy Policy Report) 1-in-10 heat wave demand forecast load growth data is utilized. To make this forecast more representative of the actual conditions, a couple of adjustments are implemented by subtracting system loss and adding station service and self-generation loads. The first year's PG&E division load is determined by adding the division Year 1 load growth to the division gross starting point. Each division's Year 1 load growth is calculated based on the CEC 1-in-10 heat wave demand forecast Year 1 growth, adjusted according to its gross starting point. For subsequent years, each division's load growth is derived by allocating the CEC 1-in-10 heat wave load growth forecast to each division. This allocation process is guided by the relative magnitude of the Distribution division level 1-in-10 load growth, ensuring that future division loads align with the expected development of the system. The following year's division load is calculated by adding the division load growth to the previous year's division load, reflecting the evolving energy demand within each division.

Allocation of Division Load to Transmission Bus Level

In the process of allocating division loads to the various transmission buses, PG&E considers distinct approaches for different load types. PG&E categorizes its loads into four types: conforming, non-conforming, self-generation, and station service loads.

Notably, non-conforming, self-generation, and station service loads are assumed to remain constant, unaffected by temperature variations. Hence, their magnitude remains unchanged in both the 1-in-5 heat wave system base case, and the 1-in-10 heat wave local area base cases for the same year.

The remaining load, which includes the total division load minus the quantity of non-conforming, self-generation, and station service loads, constitutes the conforming load. This conforming load is then allocated to the transmission buses based on the relative magnitude of the distribution planning load forecast.

In both of system 1-in-5 heat wave and local area 1-in-10 heat wave load forecast, after allocation of division load to transmission bus level, there are other load elements need to be added/adjusted to the base cases:

- non-conforming load
- BTM-PV
- CEC load modifiers AAEE, AAFS, and AATE, etc.
- Distribution Planning (DP) Hot Banks
- Municipal (Muni) Forecasts

DP Hot Banks

The DP Hot Banks interim process involves several key steps in coordination between Distribution Planning (DP) and the Transmission Planning (TP) to address potential underestimations of load forecast in areas of high growth.

Area 1-in-10 cases update the Hot Banks loading in each area cases. The hot banks are only applied to their own area cases. For instance, the GRBA Area cases only contains the hot banks in the Greater Bay Area. Area 1-in-10 load forecasts start from PG&E starting points, which are based on PG&E EMS and temperature historical data. In the Area 1-in-10 load forecast, CEC IEPR load growth is applied but the CEC IEPR load value is not. The Hot Banks process improves the accuracy of load forecasts that the high growth banks may not be reflected in the Area 1-in-10 demand forecast.

The process is as follows:

- DP works with TP to ensure correct substation mapping and identifies areas of high growth (including EV loads).
- DP reviews TP load forecast at bank level for the high growth areas and identifies the “Hot Banks” where loading could be underestimated.
  The following criteria are shown below that DP used to screen and select Hot Banks:

Model Per LoadSEER
New Business Non-EV Load Growth
EV Load Growth 2MW or greater
Known Transmission Capacity Issues
Known Transmission Reliability Issues
Transmission work required for Distribution Capacity Project
Transmission Limiting Distribution Service Connections
Existing Transmission Project Justification

- TP Area Planners review DP proposal of “hot bank” and agree (or seeking further clarification) on the DP forecast loading level.
- Area 1-in-10 cases updates the bank loading for the “Hot Banks”.

This interim process ensures a coordinated effort between DP and TP to identify potential areas where the load forecasts might not adequately account for significant growth. By identifying and addressing these "Hot Banks", the process aims to improve recent development of load forecasts that may not be factored in the CEC demand forecast in time, particularly in regions experiencing rapid development or increased energy demand.

Muni Loads in Base Case

Municipalities provide PG&E with their load forecast information. If the municipalities' total load forecasts differ from the CEC 1-in-5 and 1-in-10 demand forecasts, PG&E adjusts their bus-level loading (excluding nonconforming loads), according to the CEC forecasts. This adjustment ensures that the total loads align with the CEC forecasts, maintaining consistency across the entire system.

If municipalities do not provide their load forecast information, PG&E supplements such forecasts to ensure that the information gap is covered adequately.

For the 1-in-5 system base cases, the 1-in-5 heat wave load forecasts provided by the municipalities are utilized in the calculations. For the 1-in-10 heat wave local area base cases, the 1-in-10 load forecasts are used.

Behind-the-meter PV (BTM-PV)

The BTM-PV is integrated as a component of the load model in the following manner:

Modeling within Load Model: BTM-PV is included as part of the load model. The GE PSLF power flow software load model's DG field represents the total nameplate capacity of the DG under the PDGmax field, while the actual output is based on specific scenarios in the ISO TPP Study Plan.

Specification and Allocation: The total nameplate capacity for BTM-PV is provided by the CEC (California Energy Commission). The allocation and location of projected DG are derived from the latest DG information provided by PG&E Distribution Planning.

2.5.2.3 Southern California Edison Service Area

SCE's A-Bank Load modeling is illustrated in Figure 2.5-4. The main steps are as follows[17]:

1. Start with the California Energy Demand (CED) or California Energy Demand Update (CEDU) Forecast adopted by the California Energy Commission (CEC). The CED is provided in an odd-year Integrated Energy Policy Report (IEPR) such as 2023 IEPR, and the CEDU is provided for an even-year IEPR (i.e., 2022 IEPR). The weather-adjusted load forecast will be used depending on whether the study to be performed is a local reliability assessment, or CAISO-wide (i.e., regional) assessment. For local reliability assessment, a 1-in-10 heat wave load forecast will be used.

2. Adjust load downwards by a specific percentage, as provided by the CEC, to account for transmission losses.

3. Remove Metropolitan Water District (MWD) and California Department of Water Resources (CDWR) pump loads.

4. After Step 3, it becomes Adjusted CEC coincident forecast for SCE TAC Area. This is the total value used in the SCE Annual Transmission Reliability Assessment/CAISO Transmission Planning Process (ATRA/TPP).

5. Subtract Municipality Load (Anaheim, Pasadena, Riverside, and Vernon) and Fixed Load (e.g., Chevmain) to determine the Adjusted CEC Total Load for SCE Load Serving Entity (LSE).

6. Obtain the Subarea (i.e., LA Basin, Big Creek/Ventura, North of Lugo) Load Scaling Factor by dividing the Adjusted CEC Subarea Total Load by the Adjusted SCE Subarea Total Load (SCE's internal load forecast).

7. Calculate the <u>Modified ATRA A-Bank</u> Demand Forecast by multiplying the Subarea Load Scaling Factor by the SCE Busbar Loads. The Municipality Load and Fixed Load subtracted in Step 5 are added to complete load model.

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[17] The underlined items are the components that are included in the Example in the third diagram of this section.

8. Calculate the Adjusted ATRA A-Bank Load by subtracting the sum of AAEE, AAFS, and AATE (after adding distribution losses) from the Modified ATRA A-Bank Demand Forecast and subtracting the BTM-PV Production as shown in equation 1. The example in the third diagram in this section provides an illustration for how SCE models the CEC forecast, BTM-PV Production, and load modifiers in four (4) load bus components.

   Equation 1: Adjusted ATRA A-Bank Load =

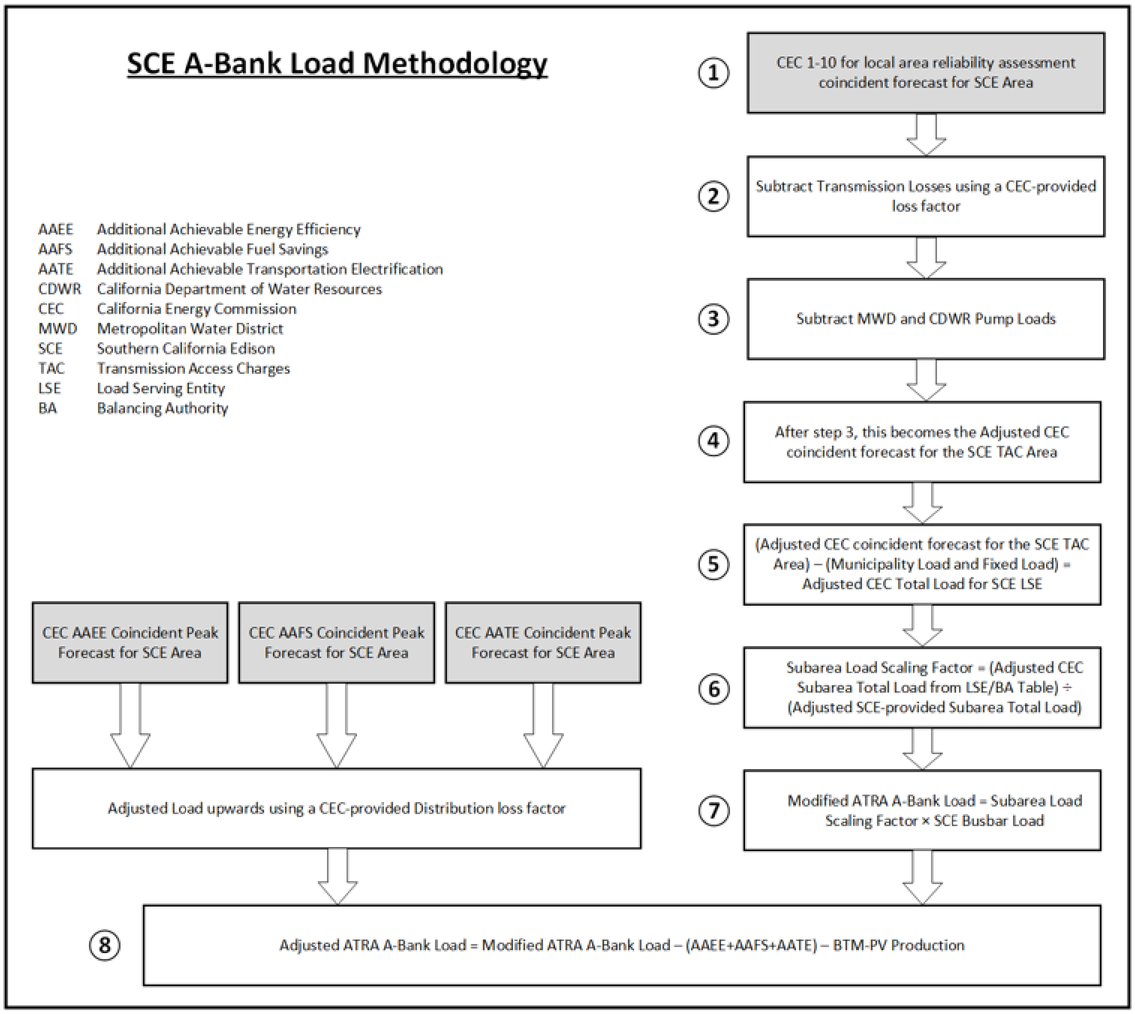
   Modified ATRA A-Bank Load – {Σ (AAEE + AAFS + AATE)} – BTM-PV Production

   where
   Modified ATRA A-Bank Load: see item 7 above and the following SCE A-Bank Load Methodology diagram; the total of all A-bank loads represents the Adjusted CEC total load for the SCE LSE area

   Adjusted ATRA A-Bank Load = one of the four load components in power flow model (see Example)
   AAEE = negative value (second bus-bar load component)
   AAFS = typically positive value (third bus-bar load component)
   AATE = positive value (fourth bus-bar load component)
   BTM-PV Production = negative "load" value (aka positive "generation production" value – see Example)

The following illustrates disaggregation of the CEC's demand forecast to SCE bus-bar load levels.

Figure 2.5-1: SCE A-Bank Load Methodology

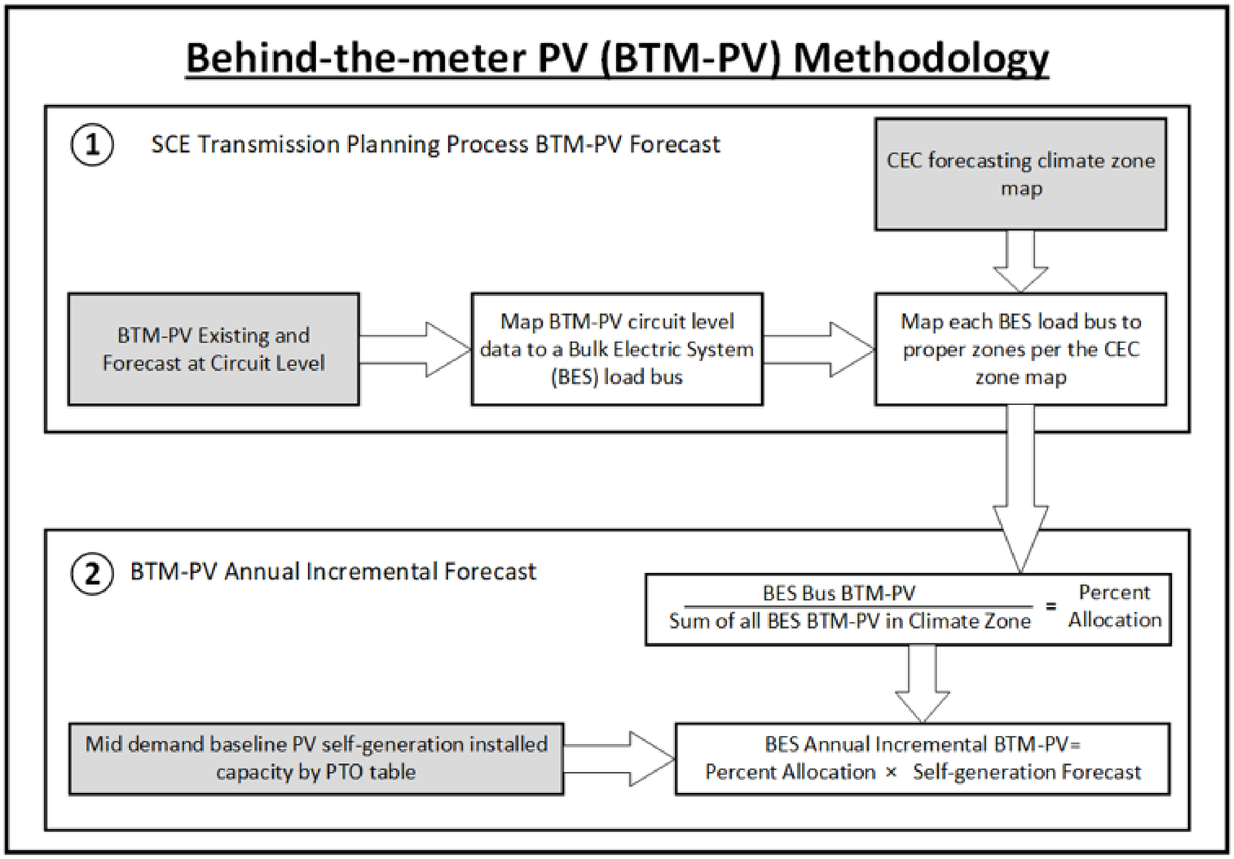


Behind-the-meter PV (BTM-PV)

The Behind-the-meter PV modeling is illustrated in Figure 2.5-2. The main steps are as follows:

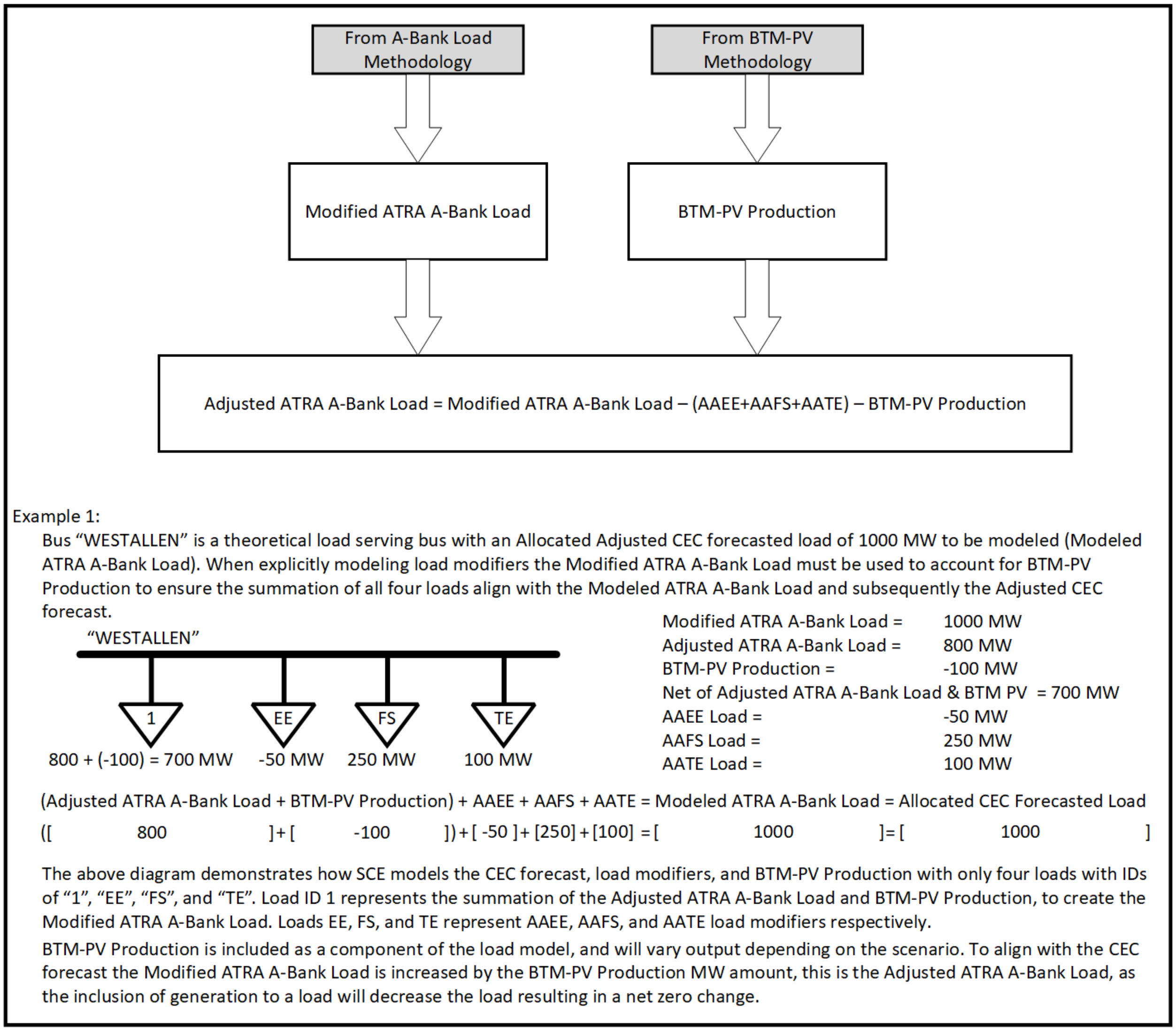
1. SCE Transmission Planning Process BTM-PV: First, the existing and forecasted BTM-PV generation is mapped to a Bulk Electric System (BES) load bus based on a forecasting climate zone map provided by the CEC.
2. BTM-PV Annual Incremental Forecast. The percent allocation is calculated by dividing each BES bus BTM-PV Production by the sum of all BES BTM-PV Production within the same climate zone. The incremental BTM-PV Production is then allocated by multiplying the self-generation PV forecast, provided by the CEC, by the calculated percent allocation for each BES load bus.

Figure 2.5-2: BTM-PV Methodology



A theoretical example of the calculation of A-Bank load and BTM-PV generation at a fictitious bus is shown in the following Figure 2.5-3.

Figure 2.5-3: Example of calculation of A-Bank load and BTM-PV Production at a fictitious bus



Load Allocation for Local Area studies

Load allocation for the SCE local area studies will continue to use the above A-Bank methodology for the system case but will be adjusted based on the load forecast developed in SCE's distribution planning process for the area case to capture area-specific needs. This forecast spans 10 years and determines load using customer load growth and DER forecasts, including energy efficiency, energy storage, plug-in electric vehicles, and distributed generation such as solar PV. The forecast is based on load profiles collected from historical data and normalized to a common temperature to account for variations in peak temperatures from year to year. In addition to a normalized 10-year forecast, the methodology also produces a forecast adjusted for 1-in-5-year heat storm conditions.

The distribution planning process uses the CEC's IEPR-derived CED forecasts to determine its base load growth forecast at the distribution circuit level. SCE disaggregates the IEPR forecast to provide the granularity necessary to account for local-area specific electrical needs. Where appropriate, SCE may also incorporate additional load growth that may not have been fully reflected in the CED forecasts. In certain scenarios, such as assessing the reliability of local load pocket areas, the non-coincident substation-level load forecast may be used. This load level, which might exceed the CEC demand forecast for the SCE TAC area, will be evaluated individually for specific load interconnection requests. For cases where the modeled loads are not included in the CEC IEPR forecast, SCE will collaborate with the CAISO and CEC to validate and agree on the load interconnection input assumptions before conducting the necessary planning studies.

2.5.2.4 San Diego Gas and Electric Service Area

SDG&E derives its coincident substation-level forecasts by adjusting its distribution non-coincident substation-level load forecast values so that the sum of all coincident loads, load bus modifiers, and transmission losses equals to the California Energy Commission (CEC's) 1-in-10 system load forecast for the SDG&E area. Consequently, every load bus in the SDG&E area includes five load components that are modeled explicitly in its TPP power flow model: SDG&E's non-coincident substation-level load forecast, SDG&E's coincident load forecast adjusted to the CEC forecast, and the three load modifiers including Additional Achievable Energy Efficiency (AAEE), Additional Achievable Transportation Electrification (AATE), and Additional Achievable Fuel Substitution (AAFS).

With the load components mentioned above, SDG&E utilizes coincident load forecast adjusted to the CEC demand forecast to perform reliability assessments as part of the TPP process. In some instances, the non-coincident substation-level load forecast is utilized in special scenarios such as reliability assessment of a local load pocket area, The use of the non-coincident load level, which may contribute to an aggregated load higher than the CEC demand forecast for the overall San Diego area, will be reviewed on a case-by-case basis for specific load interconnection requests. For this scenario where loads modeled are not accounted for in the CEC Integrated Energy Policy Report (IEPR) forecast, SDG&E will work with the ISO for further validation and concurrence of the load interconnection input assumptions prior to performing applicable planning studies.

Development of the non-coincident distribution substation-load forecast begins with assessing the historical peak loads for the distribution substations to establish a reference point for future forecast projections. The historical substation peak loads are obtained through either historical Supervisory Control and Data Acquisition (SCADA) data, or monthly-recorded substation metering data, or cumulative advanced metering infrastructure (AMI) data. Once the actual peak loads and time-stamps have been determined for the distribution substations, the historical peak demand is evaluated considering factors such as anticipated new load additions, load transfers, loss of a generator connected to the distribution circuits, weather conditions at the time of the historical peak, etc. These factors may result in adjustments to the historical loads to produce the reference points for developing the substation load forecast. Concurrently, various system information is captured as necessary to assist in disaggregation of the CEC's system-level projections of load and DER additions to the bus bar level.

Behind-the-meter PV (BTM-PV)

BTM-PV will be modeled as a component of the load model. Using the DG field on the GE PSLF power flow program load model, the total nameplate capacity of the DG will be represented under PDGmax field, and the production output will be based on the base case scenarios from the ISO TPP Study Plan. The total nameplate capacity is provided by the CEC and used to do a bus-level allocation of the BTM-PV.

2.5.2.5 Valley Electric Association Service Area

The VEA develops its substation load forecast from trending three-year historical non-coincident peak load data. The forecast is then adjusted with future known load changes. The CEC develops Statewide Energy Demand Forecasts, including a VEA forecast adjusted for weather, energy efficiency or other forecast considerations. VEA then aligns its forecast with the CEC forecast to develop loads for the various TPP base case models.

2.5.2.6 Bus-level Load Adjustments

The bus-level loads are further adjusted to account for BTM-PV and supply-side distribution connected (WDAT) resources that don't have resource ID.

2.5.3 Power Factor Assumptions

In the PG&E area assessment, power factors at all substations will be modeled using the most recent historical values obtained at corresponding peak, off-peak, and light load conditions. Bus load power factor for near term (2 year and 5 year out) will be modeled based on the actual data recorded in the EMS system. For the subsequent study years a power factor of 0.97 lagging for summer peak cases, and 0.99 leading factor for winter off-peak cases, will be used.

In the SCE area assessment, power factors at all substations will be modeled using the previous year's historical values obtained for peak, off-peak and light load conditions for the near term base cases (2 year and 5 year out). For the long term base case (10 year out), the average historical power factor for each planning area is used.

In the SDG&E area, power factors at all substations will be modeled based on the actual peak load data recorded in the EMS system for the 2 year study case. For the subsequent study years a power factor of 0.995 will be used.

In the VEA area assessment, reactive power loads at all substations will be modeled using the maximum historical seasonal values over the past four years. These values will be utilized in near-term TPP cases. For the long-term TPP cases a power factor at the transmission/distribution interface points of 0.97 lagging for summer peak cases, and 0.99 leading for winter off-peak cases, will be used.

2.5.4 Self-Generation

Draft Editorial Note:

Section 2.5.4 will be updated in the Final Study Plan with the pending CEC data. Tables 2.5-1 and 2.5-2 currently have the values from the 2024-2025 TPP.

Baseline peak demand in the CEC demand forecast is reduced by projected impacts of self-generation serving on-site customer load. Most of the increase in self-generation over the forecast period comes from PV. The CAISO wide behind-the-meter PV (BTM-PV) capacity is projected to reach 16,576 MW in the mid demand case by 2034. In 2024-2025 TPP base cases, BTM-PV generation production will be modeled explicitly. The CEDU 2023-2040 forecast also includes behind-the-meter storage as a separate line item. The combined CAISO wide, residential and non-residential behind-the-meter storage is projected to reach about 2,434 MW maximum output in the mid demand case by 2034. Behind-the-meter storage will not be modeled explicitly in 2025-2026 TPP base cases due to lack of locational information and limitation within the GE PSLF tool to model more than one distributed resources behind each load. However it will be accounted for by netting to the load.

BTM-PV installed capacity for mid demand scenario by PTO and forecasting climate zones are shown in Table 2.5-1. Output of the BTM-PV will be selected based on the time of day of the study using the end-use load and PV shapes for the day selected.

Behind-the-meter storage installed capacity for mid demand scenario by PTO and forecasting climate zones is shown in Table 2.5-2. These resources will be netted to load in the 2025-2026 TPP base cases.

A forecasting climate zone map provided by CEC is included below in Figure 2.5-4, which can be used in allocating BTM-PV to various areas for bus level forecasting.

Table 2.5-1: Mid demand baseline PV self-generation installed capacity by PTO[18]

PTO	Forecast Climate Zone	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2039
PGE	Central Coast	622	685	748	812	875	942	1009	1074	1137	1175	1210	1296
	Central Valley	1809	1905	2004	2110	2218	2337	2454	2565	2677	2748	2807	2966
	Greater Bay Area	2365	2687	3021	3384	3759	4162	4571	4896	5243	5451	5664	6117
	North Coast	610	672	733	794	855	920	985	1046	1106	1145	1187	1283
	North Valley	371	392	414	437	460	487	514	540	566	582	598	628
	Southern Valley	2217	2283	2351	2422	2492	2572	2648	2727	2805	2849	2882	3012
	PG&E Total	**7994**	**8625**	**9271**	**9959**	**10659**	**11421**	**12182**	**12848**	**13535**	**13950**	**14348**	**15302**
SCE	Big Creek East	539	555	571	589	607	629	651	673	695	707	716	756
	Big Creek West	365	412	459	506	554	606	658	705	752	777	803	887
	Eastern	1292	1376	1461	1555	1652	1765	1879	1979	2082	2139	2188	2331
	LA Metro	2449	2890	3336	3803	4276	4749	5215	5630	6065	6339	6639	7212
	Northeast	1040	1163	1287	1412	1536	1673	1808	1935	2060	2119	2171	2318
	SCE Total	**5686**	**6397**	**7114**	**7866**	**8625**	**9422**	**10212**	**10922**	**11653**	**12080**	**12517**	**13505**
SDGE	**SDGE**	**2078**	**2217**	**2355**	**2506**	**2659**	**2817**	**2972**	**3113**	**3254**	**3346**	**3432**	**3706**
CAISO Total		**15757**	**17239**	**18740**	**20332**	**21943**	**23660**	**25365**	**26883**	**28443**	**29376**	**30298**	**32512**

[18] Based on self-generation PV calculation spreadsheet provided by CEC.

Table 2.5-2: Mid demand baseline behind-the-meter storage installed capacity by PTO[19]

PTO	Forecast Climate Zone	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2039
PGE	Central Coast	70	86	102	119	137	156	176	193	211	219	228	253
	Central Valley	128	150	173	202	231	267	303	333	363	376	390	435
	Greater Bay Area	352	440	529	625	723	829	935	1025	1114	1156	1199	1310
	North Coast	131	150	169	189	210	232	255	275	295	307	318	357
	North Valley	22	28	34	42	49	59	68	76	84	88	92	101
	Southern Valley	62	77	92	109	125	146	166	184	202	210	218	253
	PG&E Total	**765**	**932**	**1099**	**1286**	**1474**	**1688**	**1903**	**2086**	**2270**	**2357**	**2444**	**2708**
SCE	Big Creek East	20	24	28	33	39	47	55	61	68	70	71	77
	Big Creek West	71	88	106	124	142	162	182	199	216	224	232	251
	Eastern	77	100	123	152	181	215	250	278	305	313	321	342
	LA Metro	471	602	733	875	1017	1161	1305	1404	1503	1549	1596	1687
	Northeast	119	158	197	236	276	322	368	404	441	452	463	484
	SCE Total	**758**	**972**	**1187**	**1420**	**1653**	**1907**	**2161**	**2347**	**2534**	**2608**	**2683**	**2841**
SDGE	**SDGE**	**219**	**251**	**283**	**325**	**366**	**412**	**457**	**493**	**529**	**544**	**559**	**614**
CAISO Total		**1743**	**2155**	**2570**	**3031**	**3493**	**4007**	**4521**	**4926**	**5332**	**5509**	**5686**	**6163**

[19] Based on behind-the-meter storage calculation spreadsheet provided by CEC.

Figure 2.5-4: CEC forecasting climate zone map

2.6 Resource Assumptions

2.6.1 New Resource Inclusion Criteria

New resources will be modeled in the studies as generally described below. Depending on the status of each resource, new resources will be assigned to one of the three levels below:

- Level 1: Resource projects that have become operational
- Level 2:
  - Resource projects on the CPUC's in-development resource list;
  - Resource projects on the POU's in-development resource list[20]; or
  - Resource projects, if any, that are not on the CPUC or POU's in-development resource list but are known to have commenced construction or have a power purchase agreement (PPA) with a load serving entity (LSE). For clarity, simply having executed generation interconnection agreement (GIA) is not sufficient to meet the resource inclusion criteria.
- Level 3: Generic resources that are included in the CPUC IRP base portfolio for use in the ISO's current transmission planning cycle to meet long term greenhouse gas emission and reliability (resource adequacy) targets and those included in the POU's approved IRP portfolio.

Based on levels above, the following guidelines will be used to model new generators in the base cases for each study.

Year 1 Operating Cases:

- Level 1 resources
- Level 2 resources that have commenced construction and have planned in-service dates within the time frame of the study.

Year 2-5 Planning Cases:

- Level 1 resources
- Level 2 resources with planned in-service dates within the 2-5 year time frame of the study.

Year 6 and beyond Planning Cases:

- Level 1 resources.
- Level 2 resources with planned in-service dates within the time frame of the study.
- Level 3 resources with a planned in-service date within the time frame of the study.

[20] Additional information related to the resource projects from the POU's can be found in section 3.3.1 Approved Non-CPUC Jurisdictional Integrated Resource Plans

2.6.2 IRP Portfolio Resources

The integrated resource planning (IRP) process is designed to ensure that the electric sector is on track to achieve the State's greenhouse gas (GHG) reduction target, at least cost, while maintaining electric service reliability and meeting other State goals. The IRP process develops resource portfolios annually as a key input to the CAISO's transmission planning process. The resources portfolios include a base portfolio, which is used in reliability, policy-driven, and economic assessments, and one or more sensitivity portfolios, which are typically used in the policy-driven assessment that is covered in section 3.

On February 14, 2025, the CPUC issued the proposed decision (PD) Revision 1[21] which will be voted on by the commission at the CPUC's February 20 Business Meeting. The PD recommends transmittal of the base case portfolio along with a sensitivity portfolio with a greater volume of long lead-time (LLT) resources for use in the 2025-2026 TPP. The base case portfolio is designed to reduce statewide yearly GHG emissions from the electric sector to 25 MMT by 2035 with load based on the CEC's 2023 IEPR Demand Forecast. The base case portfolio is comprised of in-development resources, IRPs of all LSEs and additional generic resources that are selected to achieve policy and reliability targets. The CAISO will model only the in-development resources in the near term study cases based on their in service dates in accordance with the data provided by the CPUC and POU's. The CAISO may supplement the data with information regarding contracted resources and resources that are under construction as of March 2025. Generic portfolio resources will be modeled in the long-term study cases.

CPUC staff, in collaboration with CEC and CAISO staff, have mapped the resources in the portfolios to the substation busbar level for use in the CAISO's 2025-2026 TPP.

[21] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M557/K045/557045217.pdf

Table 2.6-1: 2035 Resource additions in the base and sensitivity portfolios (in MW)

	Base Portfolio			Sensitivity Portfolio		
Resource Type	**FCDS (MW)**	**EO (MW)**	**Total (MW)**	**FCDS (MW)**	**EO (MW)**	**Total (MW)**
Biomass	171	0	171	171	0	171
Distributed_Solar	0	294	294	0	280	280
Geothermal	1,639	0	1,639	2,139	0	2,139
LDES	1,264	0	1,264	2,975	0	2,975
Li_Battery (4-hour)	16,189	0	16,189	16,189	0	16,189
Li_Battery (8-hour)	2,593	0	2,593	2,137	0	2,137
Offshore Wind	4,531	0	4,531	7,555	0	7,555
OOS Wind	9,000	0	9,000	7,000	0	7,000
Solar	5,994	13,546	19,539	4,937	12,461	17,398
Wind, Onshore	6,739	1,156	7,895	5,969	954	6,923
TOTAL	**48,120**	**14,996**	**63,115**	**49,072**	**13,695**	**62,767**

Table 2.6-2: 2040 Resource additions in the base and sensitivity portfolios (in MW)

	Base Portfolio			Sensitivity Portfolio		
Resource Type	**FCDS (MW)**	**EO (MW)**	**Total (MW)**	**FCDS (MW)**	**EO (MW)**	**Total (MW)**
Biomass	171	0	171	171	0	171
Distributed_Solar	0	294	294	0	294	294
Geothermal	1,639	0	1,639	2,139	0	2,139
LDES	1,264	0	1,264	2,785	0	2,785
Li_Battery (4-hour)	16,189	0	16,189	16,189	0	16,189
Li_Battery (8-hour)	11,770	0	11,770	10,195	0	10,195
Offshore Wind	4,531	0	4,531	7,555	0	7,555
OOS Wind	10,707	0	10,707	10,491	0	10,491
Solar	14,229	30,370	44,598	10,691	27,431	38,122
Wind, Onshore	6,739	1,156	7,895	6,252	987	7,239
TOTAL	**67,239**	**31,820**	**99,058**	**66,468**	**28,712**	**95,181**

2.6.3 Thermal generation

For the latest updates on new generation projects, please refer to the CEC website under the licensing section (https://www.energy.ca.gov/programs-and-topics/topics/power-plants/alphabetical-power-plant-listing). In addition, the CAISO may also use other data sources to track the statuses of additional generator projects to determine the starting year new projects may be modeled in the base cases.

2.6.4 Hydroelectric Generation

During drought years, the availability of hydroelectric generation production can be severely limited. In particular, during a drought year the Big Creek area of the SCE system has experienced a reduction of generation production that is 80% below average production. It is well known that the Big Creek/Ventura area is a local capacity requirement area that relies on Big Creek generation to meet NERC Planning Standards. The Sierra, Stockton and Greater Fresno local capacity areas in the PG&E system also rely on hydroelectric generation. For these areas, the CAISO will consider drought conditions when establishing the hydroelectric generation production levels in the base case assumptions.

2.6.5 Generation Retirements

Existing generators that have been identified as retiring are listed here:

http://www.caiso.com/Documents/AnnouncedRetirementAndMothballList.xlsx

These generators along with their step-up transformer banks will be modeled as out of service starting in the year they are assumed to be retired. Their models are to be removed from base cases only when they have been physically taken apart and removed from the site. Exception: models can be removed prior to physical removal only when approved plans exist to use the site for other reasons.

In addition to the identified generators the following assumptions will be made for the retirement of generation facilities.

Nuclear Retirements –Diablo Canyon will be modeled online in the near-term (Units 1 and 2) and mid-term (Unit 2 only) and off-line in the long-term scenarios based on the extension.

Once Through Cooled Retirements – As identified in section 2.6.6.

Renewable and Hydro Retirements – Assumes these resource types stay online unless there is an announced retirement date.

Other Thermal Generation Retirements – Assumes these resource types stay online unless there is an announced retirement date. The CPUC base portfolio does not identify any thermal generation retirements within the planning horizon.

2.6.6 OTC Generation

Modeling of the once-through cooled (OTC) generating units follows the compliance schedule from the State Water Resources Control Board (SWRCB)'s Policy[22] on OTC plants. The following are notable remaining OTC generating units to meet final compliance schedule:

- The OTC generating units that have been granted for compliance schedule extension by the State Water Resources Control Board [23] for participating in the State's Strategic

[22] https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc-policy-2023/otc-policy-2023.pdf

[23] https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc-policy-2023/otc-policy-2023.pdf

Reserve Reliability Program[24]. On June 30, 2022, Governor Gavin Newsom signed into law Assembly Bill 205, which created a statewide Electricity Supply Strategic Reliability Reserve Program (Strategic Reserve) to bolster system reliability while California procures clean energy resources, including extending the operations of power plants previously scheduled for retirement. These generating units include Alamitos, Huntington Beach, and Ormond Beach units that entered service in the Strategic Reserve beginning January 1, 2024. *These units are normally off-line and are only dispatched to maintain reliability during extreme or simultaneously occurring extreme events*.

- On September 2, 2022, Governor Gavin Newsom approved Senate Bill 846, which added Section 13193.5 to the California Water Code and extended the OTC Policy compliance date for Diablo Canyon Units 1 and 2 to October 31, 2030. However, the CPUC Rulemaking 23-01-007[25] decision directs and authorizes extended operations at Diablod Canyon until 10/31/2029 for Unit 1 and 10/31/2030 for Unit 2.

2.6.7 Distribution connected resources modeling assumption

Table 2.6-3 below outlines modeling assumptions for distribution connected resources in the TPP base cases.

Table 2.6-3: Modeling assumptions of distribution connected resources

POI	Size (MW)	CAISO Resource ID	PSLF Modeling	Comment
Behind-the-meter	N/A	N/A	Model as component of load	BTM resources aggregated to 0.5 MW or greater
In-front-of-the-meter	>0.5	Yes	Model as individual generator at T/D interface	0.5 MW is the minimum size requirement for resource ID
In-front-of-the-meter	>10	No	Model as individual generator at T/D interface	Load forecast may need to be adjusted for modeling these resources as generator.
In-front-of-the-meter	<10	No	Model as aggregated generator at T/D interface	Aggregate only the resources of same technology

[24] https://www.energy.ca.gov/data-reports/california-energy-planning-library/reliability/strategic-reliability-reserve

[25] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M521/K496/521496276.PDF

2.7 Preferred Resources[26]

In complying with tariff Section 24.3.3(a), the CAISO sent a market notice to interested parties seeking suggestions about demand response programs and generation or non-transmission alternatives that should be included as assumptions in the study plan.

2.7.1 Methodology

The CAISO issued a paper[27] on September 4, 2013, in which it presented a methodology to support California's policy emphasis on the use of preferred resources – specifically energy efficiency, demand response, renewable generating resources and energy storage – by considering how such resources can constitute non-conventional solutions to meet local area needs that otherwise would require new transmission or conventional generation infrastructure. The general application for this methodology is in grid area situations where a non-conventional alternative such as demand response or some mix of preferred resources could be selected as the preferred solution in the CAISO's transmission plan as an alternative to the conventional transmission or generation solution.

In previous planning cycles, the CAISO applied a variation of this new approach in the LA Basin and San Diego areas to evaluate the effectiveness of preferred resource scenarios developed by SCE as part of the procurement process to fill the authorized local capacity for the LA Basin and Moorpark areas. In addition to these efforts focused on the overall LA Basin and San Diego needs, the CAISO also made further progress in integrating preferred resources into its reliability analysis focusing on other areas where reliability issues were identified.

As in the previous planning cycles, reliability assessments in the current planning cycle will consider a range of existing demand response amounts as potential mitigations to transmission constraints. The reliability studies will also incorporate the incremental uncommitted energy efficiency and fuel substitution amounts as projected by the CEC and a mix of preferred resources including energy storage based on the CPUC authorization. These incremental preferred resource amounts are in addition to the base amounts of energy efficiency, demand response and "behind the meter" distributed or self-generation that is embedded in the CEC load forecast.

For each planning area, reliability assessments will be initially performed using preferred resources other than energy-limited preferred resources such as DR and energy storage to identify reliability concerns in the area. If reliability concerns are identified in the initial assessment, additional rounds of assessments will be performed using potentially available demand response and energy storage to determine whether these resources are a potential solution. If these preferred resources are identified as a potential mitigation, a second step - a preferred resource analysis may then be performed, if considered necessary given the mix of

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26 To be precise, "preferred resources" as defined in CPUC proceedings applies more specifically to demand response and energy efficiency, with renewable generation and combined heat and power being next in the loading order. The term is used more generally here consistent with the more general use of the resources sought ahead of conventional generation.

27 http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf

resources in the particular area, to account for the specific characteristic of each resource including use or energy limitation in the case of demand response and energy storage. An example of such a study is the special study the CAISO performed for the CEC in connection with the Puente Power Project proceeding to evaluate alternative local capacity solutions for the Moorpark area[28]. The CAISO will continue to use the methodology developed as part of the study to evaluate these types of resources.

As part of the 2024-2025 IRP, 18,782 MW of battery storage was provided in the base portfolio as listed in Table 2.6-1 and will be modeled in the year 2035 base cases. These resources can be considered as potential mitigation options, including in earlier years if needed, to address specific transmission reliability concerns identified in the reliability assessment. If a storage option is considered, it could be for informational purposes only and would be clearly documented, as a potential option to be pursued through a resource procurement process. In some situations the storage could be approved as a transmission asset[29].

2.7.2 Demand Response

For long term transmission expansion studies, the methodology described above will be utilized for considering fast-response DR and slow-response PDR resources. In 2017, the CAISO performed a study to assess the availability requirements of slow-response resources, such as demand response, to count for local resource adequacy.[30] The study found that at current levels, most existing slow-response DR resources appear to have the required availability characteristics needed for local RA if dispatched pre-contingency as a last resort, with the exception of minimum run time duration limitations. The CAISO will address duration limitations through the annual Local Capacity Requirements stakeholder process through hourly load and resource analysis.

The CAISO has developed a methodology that will allow the CAISO to dispatch slow response demand response resources after the completion of the CAISO's day-ahead market run as a preventive measure to maintain local capacity area requirements in the event of a potential contingency. Specifically, the methodology allows the CAISO to assess whether there are sufficient resources and import capability in a local capacity area to meet forecasted load without using slow response demand response. If the assessment shows insufficient generation and import capability in the local area, the CAISO will use the new methodology to determine which and how much of the available slow response demand response it should

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[28] https://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf

[29] Currently storage as a transmission asset cannot receive market revenues, and efforts to allow such market revenues have been temporarily put on hold. The following presentation provides more information: http://www.caiso.com/InitiativeDocuments/Presentation-Storage-TransmissionAsset-Jan142019.pdf

[30] CAISO-CPUC Joint Workshop, Slow Response Local Capacity Resource Assessment:

https://www.caiso.com/Documents/Presentation_JointISO_CPUCWorkshopSlowResponseLocalCapacityResourceAssessment_Oct42017.pdf commit after the completion of the day-ahead market via exceptional dispatch to reduce load for some period during the next operating day to meet the anticipated insufficiency.

The IOUs submitted information of their existing DR programs and allocation to substations, in response to the CAISO's solicitation for input on DR assumptions, serve as the basis for the supply-side DR planning assumptions included herein. Transmission and distribution loss-avoidance effects shall continue to be accounted for when considering the load impacts that supply-side DR has on the system. Table 2.7-1, Table 2.7-2, and Table 2.7-3 describe supply-side DR capacity assumptions for each IOU Load Serving Entities within CAISO BA.

Table 2.7-1: PG&E Existing DR Capacity Range

PG&E Portfolio-Adjusted DR Load Impacts for CAISO Peaking Conditions, August,1-in-2 Weather			
DR Program	**MW**	**Market Model/Level of Dispatch**	**Response time**
Base Interruptible Program (BIP)	169.2	System-wide SubLAP RDRR	30 minutes
Capacity Bidding Program (CBP)	33.8	System-wide SubLAP PDR	Day Ahead
Emergency Load Reduction Program (ELRP)	82.3	System-wide	Day Ahead and Real time
Peak Day Pricing (PDP)	15.2	System-wide	Day Ahead
SmartRate™	4.3	System-wide	Day Ahead
SmartAC™	23.9	System-wide SubLAP Selected 21 Substations PDR	None required
DRAM	NA		>30 Minutes
Total	**328.7**		

Table 2.7-2: SCE Existing DR Capacity Range

Load Impact Report, 1-in-2 weather year condition portfolio-adjusted August 2024 ex-ante DR impacts at CAISO peak			
Supply-side DR (MW)	**MW**	**Market Model/Level of Dispatch**	**Response time**
Base Interruptible Program 15 Minute (BIP-15)	145	RDRR	20 Minutes or Less
Base Interruptible Program 30 Minute (BIP-30)	269	RDRR	30 Minutes
Agricultural and Pumping Interruptible (API)	26	RDRR	20 Minutes or Less
Summer Discount Plan Residential (SDP-R)	130	RDRR, with DAM economic	20 Minutes or Less
Summer Discount Plan Commercial (SDP-C)	15	RDRR, with DAM economic	20 Minutes or Less
Smart Energy Program	40	RDRR, with DAM economic	20 Minutes or Less
Capacity Bidding Program Day-Ahead (CBP-DA)	1	PDR	Day Ahead
Emergency Load Reduction Program (ELRP)	51	PDR	Day Ahead
Total	**677**		

Table 2.7-3: SDG&E Existing DR Capacity Range

DR Load Impact – SDG&E Portfolio Adjusted for CAISO Peaking Conditions, August, Weather 1-in-2			
DR Program	**MW**	**Level of Dispatch**	**Response time**
Base Interruptible Program (BIP)	0	Discontinued on 01-01-2024 by Decision (D.) 23-12-005	
Capacity Bidding Program (CBP)	2.47	Full - Based on CAISO Award	Notices are either Day Ahead (4 pm) or Day Of
Critical Peak Pricing (CPP)	8.50	Full - Based on CAISO Award	Day Ahead (4 pm)
AC Saver – Day Ahead	0	Discontinued on 01-01-2024 by Decision (D.) 23-12-005	
AC Saver – Day Of	0	Discontinued on 01-01-2024 by Decision (D.) 23-12-005	
DRAM (demonstrated capacity)	5.01	Based on CAISO Award to the DRP	NA - Not bid into the CAISO by SDG&E
Total	**15.98**		

DR capacity will be allocated to bus-bar using the method defined in D.12-12-010, or specific bus-bar allocations provided by the IOUs. The DR capacity amounts will be modeled offline in the initial reliability study cases and will be used as potential mitigation in those planning areas where reliability concerns are identified.

The following factors in Table 2.7-4 will be applied to the DR projections to account for avoided distribution losses.

Table 2.7-4: Factors to Account for Avoided Distribution Losses

	PG&E	SCE	SDG&E
Distribution loss factors	1.091	1.068	1.082

2.8 Major Path Flows and Interchange

Power flow on the major internal paths and paths that cross Balancing Authority boundaries represents the transfers that will be modeled in the study. Firm Transmission Service and Interchange represents only a small fraction of these path flows, and is clearly included. In general, the northern California (PG&E) system has 4 major interties with the outside system and southern California. Table 2.8-1 lists the capability and power flows that will be modeled in each scenario on these paths in the northern area assessment[31].

[31] These path flows will be modeled in all base cases.

Table 2.8-1: Major Path flows in northern area (PG&E system) assessment[32]

Path	Transfer Capability/SOL (MW)	Scenario in which Path will be stressed
Path 26 (N-S)	4,000[33]	Summer Peak
PDCI (N-S)	3,100[34]	
Path 66 (N-S)	5100[35]	
Path 15 (N-S)	-5,400[36]	Spring Off Peak
Path 26 (N-S)	-3,000	
PDCI (N-S)	-975[37]	
Path 66 (N-S)	-3,675	Winter Peak

For the summer off-peak cases in the northern California study, Path 15 flow is adjusted to a level close to its rating limit of 5400 MW (S-N). This is typically done by increasing the import on Path 26 (S-N) into the PG&E service territory. The Path 26 is adjusted between 1800 MW south-to-north and 1800 MW north-to-south to maintain the stressed Path 15 as well as to balance the loads and resources in northern California. Some light load cases may model Path 26 flow close to 3000 MW in the south-to-north direction which is its rating limit. Path 66 will be modelled according to seasonal nomogram relative to the amount of northern California hydro.

Similarly, lists major paths in southern California along with their current Transfer Capability (TC) or System Operating Limit (SOL) for the planning horizon and the target flows to be modeled in the southern California assessment.

32 The winter coastal base cases in PG&E service area will model Path 26 flow at 2,800 MW (N-S) and Path 66 at 3,800 MW (N-S)

33 May not be achievable under certain system loading conditions.

34 Current operational limit is 3100 MW.

35 The Path 66 flows will be modeled to the applicable seasonal nomogram for the base case relative to the northern California hydro dispatch percentage.

36 May not be achievable under certain system loading conditions

37 Current operational limit in the south to north direction is 975 MW.

Table 2.8-2: Major Path flows in southern area (SCE and SDG&E system) assessment

Path	Transfer Capability/SOL (MW)	Target Flows (MW)	Scenario in which Path will be stressed, if applicable
Path 26 (N-S)	4,000	4,000	Summer Peak
Path 26 (S-N)	3,000	0 to 3,000	Spring Off Peak
PDCI (N-S)	3,210[38]	3,100	Summer Peak
PDCI (S-N)	975[39]	975	Spring Off Peak
West of River (WOR) (E-W)	12,150	0 to 11,200	Summer Peak
East of River (EOR) (E-W)	10,100	1,400 to 10,100	Summer Peak
East of River (EOR) (W-E)		2,000 to 7,500	Summer Peak/Spring Off peak
San Diego Import	2,765~3,565	2,400 to 3,500	Summer Peak
Path 45 (N-S)	600	0 to 600	Summer Peak
Path 45 (S-N)	800	0 to 300	Spring Off Peak
Harry Allen-Eldorado (Path 84) (N-S)	3496	1000-3000	Spring Off Peak/Summer Peak
Harry Allen-Eldorado (Path 84) (S-N)	1390	500-1000	Summer Peak/Spring Off-Peak
SunZia HVDC Transmission Project (E-W)	3000[40]	1000 - 3000[41] 2131[42] (Pinal Central – Palo Verde)	Summer Peak/Winter Peak/Spring Off-Peak
TransWest Express Project (HVDC portion from TWE-Wyoming to TWE-Intermountain) (N-S)	3000	1000 - 3000[43]	Summer Peak/Winter Peak/Spring Off-Peak
TransWest Express Project (from TWE-Intermountain to TWE-Crystal HVAC Line) (N-S)	1500	1500	Summer Peak/Winter Peak/Spring Off-Peak
TransWest Express Project (from TWE-Crystal to TWE-Eldorado HVAC Line) (N-S)	1680	1680	Summer Peak/Winter Peak/Spring Off-Peak

38 WECC Existing Path rating is 3200MW, Current operational limit is 3100 MW.

39 WECC Existing Path rating is 3100MW, Current operational limit is 975 MW.

40 https://www.wecc.org/wecc-document/6136

41 The amount of flows on SunZia Transmission Project is dependent on the amount of generation modeled for the Project.

42 PowerCo currently holds 2,131 MW of long-term, firm point-to-point transmission service rights from the Pinal Central Substation to the Palo Verde Hub.

43 The amount of flows on TWE-Wyoming to TWE-Intermountain is dependent on the amount of generation modeled for the Project.

2.9 Operating Procedures

Operating procedures, for both normal (pre-contingency) and emergency (post-contingency) conditions, are modeled in the studies.

Please refer to http://www.caiso.com/market/Pages/TransmissionOperations/Default.aspx for the list of publicly available Operating Procedures.

2.10 Study Scenario

2.10.1 Base Scenario

The base scenario covers critical system conditions driven by several factors such as:

Generation:

Existing and future generation resources are modeled and dispatched to reliably operate the system under stressed system conditions. More details regarding generation modeling is provided in section 2.6.

Demand Level:

Since most of the CAISO footprint is a summer peaking area, summer peak conditions will be evaluated in all study areas. With hourly demand forecast being available from CEC, all base scenarios representing peak load conditions, for both summer and winter, will represent hour of the highest net (managed) load. The net peak hour reflects changes in peak hours brought on by demand modifiers. Furthermore, for the coincident system peak load scenarios, the hour of the highest net load will be consistent with the hour identified in the CEC demand forecast report. For the non-coincident local peaks scenarios, the net peak hour may represent hour of the highest net load for the local area. Winter peak, spring off-peak, summer off-peak or summer partial-peak will also be studied for areas in where such scenarios may result in more stress on system conditions. Examples of these areas are the coastal sub-transmission systems in the PG&E service area (e.g. Humboldt, North Coast/North Bay, San Francisco, Peninsula and Central Coast), which will be studied for both the summer and winter peak conditions. Table 2.10-1 lists the studies that will be conducted in this planning cycle.

Path flows:

For local area studies, transfers on import and monitored internal paths will be modeled as required to serve load in conjunction with internal generation resources. For bulk system studies, major import and internal transfer paths will be stressed as described in Section 2.9 to assess their FAC-013-2 Transfer Capability or FAC-014-2 System Operating Limits (SOL) for the planning horizon, as applicable.

The base scenarios for the reliability analysis are provided in Table 2.10-1.

Table 2.10-1: Summary of Base Scenario Studies in the CAISO Reliability Assessment

Study Area	Near-term Planning Horizon		Long-term Planning Horizon	
	2027	2030	2035	2040
California ISO Bulk System			Summer Peak Spring Off-Peak [44]	Summer Peak
Northern California (PG&E) Bulk System	Summer Peak Spring Off-Peak	Summer Peak	Winter Off-Peak	Summer Peak Winter peak
Humboldt	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak	Summer Peak Spring Off-Peak	
North Coast and North Bay	Summer Peak Winter peak Spring Off-Peak	Summer Peak Winter Peak	Summer Peak Spring Off-Peak	Winter peak
North Valley	Summer Peak Spring Off-Peak	Summer Peak	Summer Peak Spring Off-Peak	
Central Valley (Sacramento, Sierra, Stockton)	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak	Summer Peak Spring Off-Peak	
Greater Bay Area	Summer Peak Winter peak Spring Off-Peak	Summer Peak Winter peak	Summer Peak Spring Off-Peak	Summer peak Winter Peak
Greater Fresno	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak	Summer Peak Spring Off-Peak	
Kern	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak	Summer Peak Spring Off-Peak	
Central Coast & Los Padres	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak	Summer Peak Spring Off-Peak	Winter peak
Southern California Bulk transmission system	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak		
SCE Main Area	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak	Summer Peak Spring Off-Peak	Summer Peak Winter Peak
SCE Northern Area	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak	Summer Peak Spring Off-Peak	
SCE North of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak	Summer Peak Spring Off-Peak	
SCE East of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak	Summer Peak Spring Off-Peak	
SCE Eastern Area	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak	Summer Peak Spring Off-Peak	
SDG&E Area	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak	Summer Peak Spring Off-Peak	Summer Peak Winter Peak
Valley Electric Association	Summer Peak Spring Off-Peak	Summer Peak	Summer Peak Spring Off-Peak	Summer Peak Winter Peak

[44] The frequency response assessment will utilize the 2035 Spring Off-Peak

2.10.2 Baseline Scenario Definitions and Renewable Generation Dispatch for System-wide Cases

The data in Table 2.10-2, except for the transmission connected renewable dispatch, is derived from the latest CEC hourly forecast. As such, the scenario descriptions and corresponding renewable dispatch are applicable to CAISO system-wide cases only and may not be applicable to non-coincident local peak cases which may represent different hour than the hour the system-wide case represent. The transmission connected renewable dispatch are derived from solar and wind profiles used in production cost model.

Table 2.10-2: Baseline Scenario Definitions and Renewable Generation Dispatch

PTO	Scenario	Day/Time				BTM-PV*			Transmission Connected PV			Transmission Connected Wind			% of managed peak load		
		2027	2030	2035	2040	2027	2030	2035 and 2040	2027	2030	2035 and 2040	2027	2030	2035 and 2040	2027	2030	2035 and 2040
PG&E	Summer Off Peak	N/A	8/21 HE15	N/A	N/A	N/A	71%	N/A	N/A	79%	N/A	N/A	30%	N/A	N/A	90%	N/A
PG&E	Summer Peak	8/18 HE 18	8/21 HE 18	See CAISO	See CAISO	13%	14%	See CAISO	1%	1%	See CAISO	86%	86%	See CAISO	100%	100%	See CAISO
PG&E	Spring Off Peak	4/29 HE 20	N/A	See CAISO	N/A	0%	N/A	See CAISO and N/A	0%	N/A	See CAISO and N/A	55%	N/A	See CAISO and N/A	57%	N/A	See CAISO and N/A
PG&E	Winter Off peak	N/A	N/A	2/7 HE 12	N/A	N/A	N/A	65% and N/A	N/A	N/A	40% and N/A	N/A	N/A	96% and N/A	N/A	N/A	93% and N/A
PG&E	Winter peak	12/8 HE 19	2/6 HE 8	N/A	02/01 HE8	0%	3%	N/A and 3%	0%	31%	N/A and 31%	50%	75%	75% and N/A	69%	77%	90% and N/A
SCE	Summer Off Peak	N/A	9/5 HE 14	N/A	N/A	N/A	80%	N/A	N/A	92%	N/A	N/A	38%	N/A	N/A	85%	N/A
SCE	Summer Peak	8/11 HE 16	9/4 HE15	9/5 HE15	9/5 HE15	56%	66%	65% and 65%	60%	80%	80% and 80%	63%	46%	46% and 46%	100%	100%	100% and 100%
SCE	Spring Off Peak	4/29 HE 19	N/A	See CAISO	N/A	1%	N/A	See CAISO and N/A	0%	N/A	See CAISO and N/A	51%	N/A	See CAISO and N/A	58%	N/A	See CAISO and N/A
SCE	Winter Peak	N/A	N/A	N/A	02/01 HE 8	N/A	N/A	N/A and 8%	N/A	N/A	N/A and 35%	N/A	N/A	N/A and 54%	N/A	N/A	N/A and 92%
SDG&E	Summer Off Peak	N/A	9/4 HE 15	N/A	N/A	N/A	64%	N/A	N/A	67%	N/A	N/A	3%	N/A	N/A	94%	N/A
SDG&E	Summer Peak	9/1 HE 18	9/4 HE 18	9/5 HE 18	9/5 HE15	6%	6%	6% and 64%	2%	2%	2% and 67%	25%	25%	25% and 3%	100%	100%	100% and 100%
SDG&E	Spring Off Peak	4/22 HE 19	N/A	See CAISO	N/A	1%	N/A	See CAISO and N/A	0%	N/A	See CAISO and N/A	54%	N/A	See CAISO and N/A	69%	N/A	See CAISO and N/A
SDG&E	Winter Peak	N/A	N/A	N/A	02/01 HE 8	N/A	N/A	N/A and 8%	N/A	N/A	N/A and 35%	N/A	N/A	N/A and 24%	N/A	N/A	N/A and 92%
VEA	Summer Peak	6/26 HE 16	6/22 HE16	6/23 HE16	6/24 HE16	N/A	N/A	N/A	36%	36%	36%	N/A	N/A	51%	100%	100%	100%
VEA	Spring Off Peak	4/29 HE 19	N/A	See CAISO	N/A	N/A	N/A	N/A	0%	88%	See CAISO	N/A	N/A	See CAISO	62%	14%	See CAISO
VEA	Winter Peak	N/A	N/A	12/25 HE8	N/A	N/A	N/A	N/A	N/A	N/A	29%	N/A	N/A	24%	N/A	N/A	90%

PTO	Scenario	Day/Time	BTM-PV			Transmission Connected PV			Transmission Connected Wind			% of non-coincident PTO managed peak load		
			PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE
CAISO	2040 Summer peak	9/5 HE 18	1%	0%	6%	3%	1%	2%	32%	32%	25%	96%	97%	100%
	2035 Summer Peak	9/5 HE 18	8%	6%	6%	3%	1%	2%	32%	32%	25%	97%	93%	100%
	2035 Spring Off Peak[2]	3/25 HE 13	81%	83%	92%	90%	95%	97%	21%	22%	14%	35%	26%	19%

Note: Biomass, biogas and geothermal renewable generations are to be dispatched at NQC for all base scenarios.

Draft Editorial Note:

Table 2.10-2 BTM-PV Column currently calculated using Maximum BTM-PV Output. These values will be updated using BTM-PV installed capacity in the final study plan based on the information to be received from the CEC.

2.10.3 Sensitivity Studies

In addition to the base scenario studies that the CAISO will be assessing in the reliability analysis for the 2024-2025 transmission planning process, the CAISO will also be conducting sensitivity studies identified in Table 2.10-3. The sensitivity studies are to assess impacts of changes to specific assumptions on the reliability of the transmission system. These sensitivity studies include impacts of load forecast, generation dispatch, generation retirement and transfers on major paths.

Table 2.10-3: Summary of Sensitivity Studies in the CAISO Reliability Assessment

Sensitivity Study	Near-term Planning Horizon		Long-term Planning Horizon	
	2027	2030	2035	2040
Summer Peak with high CEC forecasted load	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Area		
Spring shoulder-peak with heavy renewable output or different import level or storage charging	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Area VEA Area	-		
Summer Peak with heavy renewable output and minimum gas generation commitment	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Area	-		
Summer Peak with forecasted load addition	VEA Area	VEA Area		
Summer Peak with Additional EV charging and building electrification scenario				PG&E Local Areas

2.10.4 Sensitivity Scenario Definitions and Renewable Generation Dispatch

Table 2.10-4: Sensitivity Scenario Definitions and Renewable Generation Dispatch

PTO	Scenario	Starting Baseline Case	BTM-PV		Transmission Connected PV		Transmission Connected Wind		Comment
			Baseline	Sensitivity	Baseline	Sensitivity	Baseline	Sensitivity	
PG&E	Summer Peak with heavy renewable output and minimum gas generation commitment	2027 Summer Peak	4%	99%	2%	99%	91%	62%	Solar and wind dispatch increased to 20% exceedance values
	Spring shoulder-peak with heavy renewable output or different import level	2027 Spring Off-Peak	0%	0%	0%	0%	82%	47%	Different import levels on COI and P26.
	Summer Peak with high CEC forecasted load	2030 Summer Peak	5%	5%	2%	11%	91%	54%	Load increased by turning off AAEE
	South Bay high load sensitivity	2035 Greater Bay area Summer peak	8%	8%	7%	7%	32%	32%	Potential upcoming load centers in Greater Bay area region
	Summer Peak with Additional EV charging and building electrification scenario	2040 Summer Peak	TBD	TBD	TBD	TBD	TBD	TBD	TBD
SCE	Summer Peak with heavy renewable output and minimum gas generation commitment	2027 Summer Peak	54%	99%	60%	99%	63%	67%	Solar and wind dispatch increased to 20% exceedance values
	Spring shoulder-peak with heavy renewable output or different import level or storage charging	2027 Spring Off-Peak	1%	1%	1%	1%	77%	77%	Storage Charging in load pockets.
	Summer Peak with high CEC forecasted load	2030 Summer Peak	30%	30%	30%	30%	68%	68%	Load increased per CEC high load scenario
SDG&E	Summer Peak with heavy renewable output and minimum gas generation commitment	2027 Summer Peak	6%	96%	2%	97%	25%	76%	Solar and wind dispatches increased to 20% exceedance values
	Spring shoulder-peak with heavy renewable output or different import level or storage charging	2027 Spring Off-Peak	1%	1%	0%	0%	54%	54%	Storage Charging in load pockets.
	Summer Peak with high CEC forecasted load	2030 Summer Peak	6%	6%	2%	2%	25%	25%	Load increased per CEC high load scenario
VEA	Summer Peak with forecasted load addition	2027 Summe Peak	N/A	N/A	36%	36%	N/A	N/A	Load increase reflect future load service request
	Summer Peak with forecasted load addition	2030Summer Peak	N/A	N/A	36%	36%	N/A	N/A	Load increase reflect future load service request
	Spring Off-peak with storage charging	2027 Spring Off-Peak	N/A	N/A	0%	0%	N/A	N/A	Storage charging

The following baselines & sensitivity scenarios will be utilized for dynamic stability assessment in this planning cycle:

- Year-2 off-peak baseline
- Year-2 off-peak sensitivity
- Year-5 peak baseline
- Year-5 peak (high load) sensitivity
- Year-10 peak baseline
- Year-10 off-peak baseline

2.11 Study Base Cases

The power flow base cases from WECC will be used as the starting point of the CAISO transmission plan base cases[45]. Table 2.11-1 shows WECC base cases will be used to represent the area outside the CAISO control area for each study year. For dynamic stability studies, the latest available Master Dynamics File (MDF)[46] will be tuned for use with specific WECC starting cases (see paragraph above for study cases that will be used for dynamic stability assessment). Dynamic load models will be added to this file.

Table 2.11-1: Summary of WECC Base Cases used to represent system outside CAISO

Study Year	Season	WECC Base Case	Year Published
2027	Summer Peak	2025 Heavy Summer 4	08/28/2024
	Winter Peak	2024-25 Heavy Winter 3 2025-26 Heavy Winter 3 (if approved before base case development)	3/26/2024 TBD
	Spring Off-Peak	2025 Heavy Spring 1	06/05/2024
2030	Summer Peak	2030 Heavy Summer 2	12/05/2024
	Summer Off-Peak	2030 Heavy Summer 2	12/05/2024
	Winter Peak	2029-30 Heavy winter 2	09/20/2024
	Spring Off-Peak	2025 Light Spring 1 2026 Light Spring 1 (if approved before base case development)	03/01/2024 TBD
2035	Summer Peak	2035 Heavy Summer 1	10/18/2024
	Spring Off-Peak	2034 Light Spring 1	11/21/2024
	Winter Peak	2033-34 Heavy Winter 1 2034-35 Heavy winter 1 (if approved before base case development)	09/08/2023 TBD
	Winter off-peak	2024-25 Light winter 1	04/05/2024
2040	Summer Peak Spring off-peak Winter Peak	2035 Heavy Summer 1 2034 Light Spring 1 2034-35 Heavy winter 1	10/18/2024 11/21/2024 12/19/2024

During the course of developing the transmission plan base cases, the portion of areas that will be studied in each WECC base case will be updated by the latest information provided by the PTOs. After the updated topology has been incorporated, the base cases will be adjusted to

[45] The starting WECC power flow cases and dynamic data are to be used by all applicable PTOs to help facilitate CAISO base case development.

[46] The CAISO used the MDF posted on 2/8/2021 on the WECC website and tuned it for specific WECC power flow cases (see top paragraph above for cases requiring dynamic simulation) as starting cases for further development of the TPP-related study cases.

represent the conditions outlined in the Study Plan. For example, a 2035 summer peak base case for the northern California will use 35HS1a1 base case from WECC as the starting point. However, the network representation in northern California will be updated with the latest information provided by the PTO followed by some adjustments on load level or generation dispatch to ensure the case represents the assumptions described in this document. This practice will result in better accuracy of network representation both inside and outside the study area.

2.12 Contingencies

In addition to the system under normal conditions (P0), the following categories of contingencies on the BES equipment will be evaluated as part of the study. For the non-BES facilities under CAISO operational control, as mentioned in section 2.1.3, TPL-001-5 categories P0, P1 and P3 contingencies will be evaluated. These contingencies lists will be made available on the CAISO secured website.

Single contingency (Category P1)
The assessment will consider all possible Category P1 contingencies based upon the following:

- Loss of one generator (P1.1)[47][48]
- Loss of one transmission circuit (P1.2)
- Loss of one transformer (P1.3)
- Loss of one shunt device (P1.4)
- Loss of a single pole of DC lines (P1.5)

Single contingency (Category P2)
The assessment will consider all possible Category P2 contingencies based upon the following:

- Loss of one transmission circuit without a fault (P2.1)
- Loss of one bus section (P2.2)
- Loss of one breaker (internal fault) (non-bus-tie-breaker) (P2.3)
- Loss of one breaker (internal fault) (bus-tie-breaker) (P2.4)

Multiple contingency (Category P3)
The assessment will consider the Category P3 contingencies with the loss of a *generator unit* followed by system adjustments and the loss of the following:

- Loss of one generator (P3.1)[49]
- Loss of one transmission circuit (P3.2)
- Loss of one transformer (P3.3)
- Loss of one shunt device (P3.4)
- Loss of a single pole of DC lines (P3.5)

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[47] Includes per California ISO Planning Standards – Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard.
[48] All generators with nameplate rating exceeding 20 MVA must be included in the contingency list
[49] Includes per California ISO Planning Standards – Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard.

Multiple contingency (Category P4)
The assessment will consider the Category P4 contingencies with the loss of multiple elements caused by a stuck breaker (non-bus-tie-breaker for P4.1-P4.5) attempting to clear a fault on one of the following:

- Loss of one generator (P4.1)
- Loss of one transmission circuit (P4.2)
- Loss of one transformer (P4.3)
- Loss of one shunt device (P4.4)
- Loss of one bus section (P4.5)
- Loss of a bus-tie-breaker (P4.6)

Multiple contingency (Category P5)
The assessment will consider the Category P5 contingencies with delayed fault clearing due to the failure of a non-redundant component of protection system protecting the faulted element to operate as designed, for one of the following:

- Loss of one generator (P5.1)
- Loss of one transmission circuit (P5.2)
- Loss of one transformer (P5.3)
- Loss of one shunt device (P5.4)
- Loss of one bus section (P5.5)

Multiple contingency (Category P6)
The assessment will consider the Category P6 contingencies with the loss of two or more (non-generator unit) elements with system adjustment between them, which produce the more severe system results.

Multiple contingency (Category P7)
The assessment will consider the Category P7 contingencies for the loss of a common structure as follows:

- Any two adjacent circuits on common structure[50] (P7.1)
- Loss of a bipolar DC lines (P7.2)

Extreme contingencies (TPL-001-5)

As a part of the planning assessment the CAISO assesses Extreme Event contingencies per the requirements of TPL-001-5; however the analysis of Extreme Events will not be included within the Transmission Plan unless these requirements drive the need for mitigation plans to be developed.

[50] Excludes circuits that share a common structure or common right-of-way for 1 mile or less.

2.12.1 Known Outages and Outage scheduling Assessment

Requirements R2.1.4 and R2.4.4 of TPL-001-5 require the planning assessment for the near-term transmission planning horizon portion of the steady state analysis [R2.1.4] and stability analysis [R2.4.4] to include assessment of the impact of selected known outages on System performance.

The CAISO Planning Standard also recognizes that scheduled outages are necessary to support reliable grid operations. The CAISO Planning Standard requires the P0 and P1 performance requirements in NERC TPL-001-5 for either BES or non-BES facilities must be maintained during scheduled outages. The standard stipulates Corrective Action Plans must be implemented when it is established through a combination of real-time data and technical studies that there is no window to accommodate necessary scheduled outages.

The CAISO will generally utilize studies of category P1 to P7 events on the year-2 system off-peak load case, which is designed to reflect a heavy load level the system is expected to experience during the period outages are normally planned, to assess the steady state and stability impact of planned outages. For example, each Category P3 and P6 contingency event will also be considered to represent the occurrence of a Category P1 event during the planned outage of a generation or a transmission facility, respectively. Accordingly, these events must meet the performance requirement for P1 for the purposes of the known or planned outage study. If an known outage expected to produce more severe System impacts on the BES is scheduled to take place under system peak conditions, the appropriate system peak base case will be used to perform the know outage study.

The above approach covers known or planned outages that involve single facilities, but not BES bus section outages, circuit breaker outages and construction-related outages that affect multiple facilities. The planned outage study will include planned outages that may affect multiple facilities in order to insure that the system can withstand P1 contingencies during such outages. Those bus section and circuit breaker outages that are known or expected to cause outage scheduling challenges will be selected, based on information provided by the Transmission Operator. Construction-related outages that affect multiple facilities will be studied, based on information provided by the Transmission Owner.

Any issues or conflicts identified with planned outages in the assessment described above will be documented in the IRO-017 Requirement R4[51] Planned Outage Mitigation Plan in addition to the transmission plan.

Table 2.12-1 provides the known or potential outages involving multiple facilities that can cause outage scheduling challenges that are selected for assessment in the current transmission planning cycle based on information obtained from TOs and TOPs. Single element outages are not listed in the table unless they are scheduled to be performed during the summer peak

[51] IRO-017-1 Requirement R4 Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.

season because, as mentioned above, they are assessed using the results of category P1 to P7 contingency studies.

Table 2.12-1: Known outages involving multiple facilities selected for assessment[52]

PTO Area	Scheduled Outage Involving Multiple Facilities	Facilities Affected	Additional Description, If Needed
PG&E	None		
SCE	None		
SDG&E	TL695 Talega – Basilone 69 kV line[1]	Same	To be evaluated on the 2027 Spring off-peak and Summer peak load conditions
SDG&E	TL6971 Basilone – Japanese Mesa 69 kV line[1]	Same	To be evaluated on the 2027 Spring off-peak and Summer peak load conditions

[1] SDG&E single 69 kV line outages are included because the planning assessment does not normally include P6 outages for non BES facilities.

2.13 Study Tools

The General Electric Positive Sequence Load Flow (GE PSLF) is the main study tool for evaluating system performance under normal conditions and following the outages (contingencies) of transmission system components for post-transient and transient stability studies. PowerGem TARA is used for steady state contingency analysis. However, other tools such as DSA tools software may be used in other studies such as voltage stability, small signal stability analyses and transient stability studies. The studies in the local areas focus on the impact from the grid under system normal conditions and following the Categories P1-P7 outages of equipment at the voltage level 60 through 500 kV. In the bulk system assessments, governor power flow will be used to evaluate system performance following the contingencies of equipment at voltage level 230 kV and higher.

2.13.1 Technical Studies

The section explains the methodology that will be used in the study:

[52] The CAISO will continue to work with PTOs to add and assess any other relevant outages during the course of the assessment.

2.13.2 Steady State Contingency Analysis

The CAISO will perform power flow contingency analyses based on the CAISO Planning Standards[53] which are based on the NERC reliability standards and WECC regional criteria for all local areas studied in the CAISO controlled grid and with select contingencies outside of the CAISO controlled grid. The transmission system will be evaluated under normal system conditions NERC Category P0 (TPL 001-5), against normal ratings and normal voltage ranges, as well as emergency conditions NERC Category P1-P7 (TPL 001-5) contingencies against emergency ratings and emergency voltage range as identified in Section 2.13.6. For some areas, operations limitation may need to be considered depending upon the specific load characteristic and duration of the emergency ratings.

Depending on the type and technology of a power plant, several G-1 contingencies represent an outage of the whole power plant (multiple units)[54]. Examples of these outages are combined cycle power plants such as Delta Energy Center and Otay Mesa power plant. Such outages are studied as G-1 contingencies.

Line and transformer bank ratings in the power flow cases will be updated to reflect the rating of the most limiting component. This includes substation circuit breakers, disconnect switches, bus position related conductors, and wave traps.

The contingency analysis will simulate the removal of all elements that the protection system and other automatic controls are expected to disconnect for each contingency without operator intervention. The analyses will include the impact of subsequent tripping of transmission elements where relay loadability limits are exceeded and generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations unless corrective action plan is developed to address the loading and voltages concerns.

Power flow studies will be performed in accordance with PRC-023 to determine which of the facilities (transmission lines operated below 200 kV and transformers with low voltage terminals connected below 200 kV) in the Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities below 200 kV that must meet PRC-023 to prevent potential cascade tripping that may occur when protective relay settings limit transmission load ability.

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[53] California ISO Planning Standards are posted on the CAISO website at

http://www.caiso.com/Documents/ISO-Planning-Standards-Effective-Feb22023.pdf

[54] Per California ISO Planning standards Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard

2.13.3 Post Transient Analyses

Post Transient analyses will be conducted to determine if the system is in compliance with the WECC Post Transient Voltage Deviation Standard in the bulk system assessments and if there are thermal overloads on the bulk system.

2.13.4 Post Transient Voltage Stability Analyses

Post Transient Voltage stability analyses will be conducted as part of bulk system assessment for the outages for which the power flow analyses indicated significant voltage drops, using two methodologies: Post Transient Voltage Deviation Analyses and Reactive Power Margin analyses.

2.13.5 Post Transient Voltage Deviation Analyses

Contingencies that showed significant voltage deviations in the power flow studies will be selected for further analysis using WECC standards.

2.13.6 Voltage Stability and Reactive Power Margin Analyses

Contingencies that showed significant voltage deviations in the power flow studies may be selected for further analysis using WECC standards. As per WECC regional criterion, voltage stability is required for the area modeled at a minimum of 105% of the reference load level or path flow for system normal conditions (Category P0) and for single contingencies (Category P1). For other contingencies (Category P2-P7), post-transient voltage stability is required at a minimum of 102.5% of the reference load level or path flow. The approved guide for voltage support and reactive power, by WECC TSS on March 30, 2006, will be utilized for the analyses in the CAISO controlled grid. According to the guideline, load will be increased by 5% for Category P1 and 2.5% for other contingencies Category P2-P7 and will be studied to determine if the system has sufficient reactive margin. This study will be conducted in the areas that have voltage and reactive concerns throughout the system.

2.13.7 Transient Stability Analyses

Transient stability analyses will also be conducted as part of bulk area system assessment for critical contingencies to determine if the system is stable and exhibits positive damping of oscillations and if transient stability criteria are met as per WECC criteria and CAISO Planning Standards. No generating unit shall pull out of synchronism for planning event P1. For planning events P2 through P7: when a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any transmission system elements other than the generating unit and its directly connected facilities.

The analysis will simulate the removal of all elements that the protection system and other automatic controls are expected to disconnect for each contingency without operator intervention. The analyses will include the impact of subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a fault where high speed reclosing is utilized.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability.
- Tripping of transmission lines and transformers where transient swings cause protection system operation based on generic or actual relay models.

The expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities will be simulated when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

2.13.8 Cascading Studies

NERC Standard FAC-014-3 is to ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies and that Planning Assessment performance criteria is coordinated with these methodologies.

The CAISO will perform cascading studies using WECC Planning Standard criteria.Cascading criteria will be applicable when a facility loading exceeds 125% of the highest seasonal facility rating as discussed in section 2.1.4 above.

PowerGem TARA will be used for performing Cascading studies for steady state in near term case.

2.14 Corrective Action Plans

Corrective action plans will be developed to address reliability concerns identified through the technical studies mentioned in the previous section. The CAISO will consider both transmission and non-transmission alternatives in developing the required corrective action plans.

Transmission and non-transmission alternatives include the consideration of Grid-Enhancing Technologies (GETs). The term GETs is used to describe advanced conductors (high temperature, low sag characteristics), dynamic line ratings, power flow controllers, and topology optimizations. The CAISO typically considers advanced conductors and power flow controllers as planning tools providing an alternative to other capital expenditures. The CAISO also considers dynamic thermal line ratings and topology optimizations in accessing operational benefits through additional capacity providing economic or emergency measure uses. The CAISO supports the application and deployment of GETs in the Transmission Planning

Process, and has considered them as potential alternatives in previous transmission planning processes.

Within the non-transmission alternative, consideration will be given to both conventional generation and in particular, preferred resources such as energy efficiency, demand response, renewable generating resources and energy storage programs. In making this determination, the CAISO, in coordination with each Participating TO with a PTO Service Territory and other Market Participants, shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as acceleration or expansion of existing projects, demand-side management, special protection systems, generation curtailment, interruptible loads, storage facilities or reactive support. The CAISO uses deficiencies identified in sensitivity studies mostly to help develop scope for corrective action plans required to mitigate deficiencies identified in baseline studies. However, the CAISO might consider developing corrective action plan for deficiencies identified in sensitivity studies on a case by case basis.

3. Policy Driven RPS Transmission Plan Analysis

With FERC's approval of the CAISO's revised TPP in December 2010, the specification of public policy objectives for transmission planning was incorporated into phase 1 of the TPP.

3.1 Public Policy Objectives

The TPP framework includes a category of transmission additions and upgrades to enable the CAISO to plan for and approve new transmission needed to support state or federal public policy requirements and directives. The impetus for the "policy-driven" category was the recognition that California's renewable energy goal would drive the development of substantial amounts of new renewable supply resources over the next decade, which in turn would drive the majority of new transmission needed in the same time frame. It was also recognized that new transmission needed to support the state's renewable energy goal would most likely not meet the criteria for the two predominant transmission categories of reliability and economic projects.

Evaluation of the need for policy-driven transmission elements begins in Phase 1 with the CAISO's specification, in the context of the unified planning assumptions and study plan, of the public policy objectives it proposes to adopt for transmission planning purposes in the current cycle. For the 2025-2026 planning cycle, the overarching public policy objective is the state's mandate for meeting renewable energy and greenhouse gas (GHG) reduction targets as described in Senate Bill (SB) 350 as well as in Senate Bill (SB) 100. For purposes of the TPP study process, this high-level objective is comprised of two sub-objectives: first, to support the economic delivery of renewable energy over the course of all hours of the year, and second, to support Resource Adequacy (RA) deliverability status for the renewable resources identified in the portfolio as requiring that status.

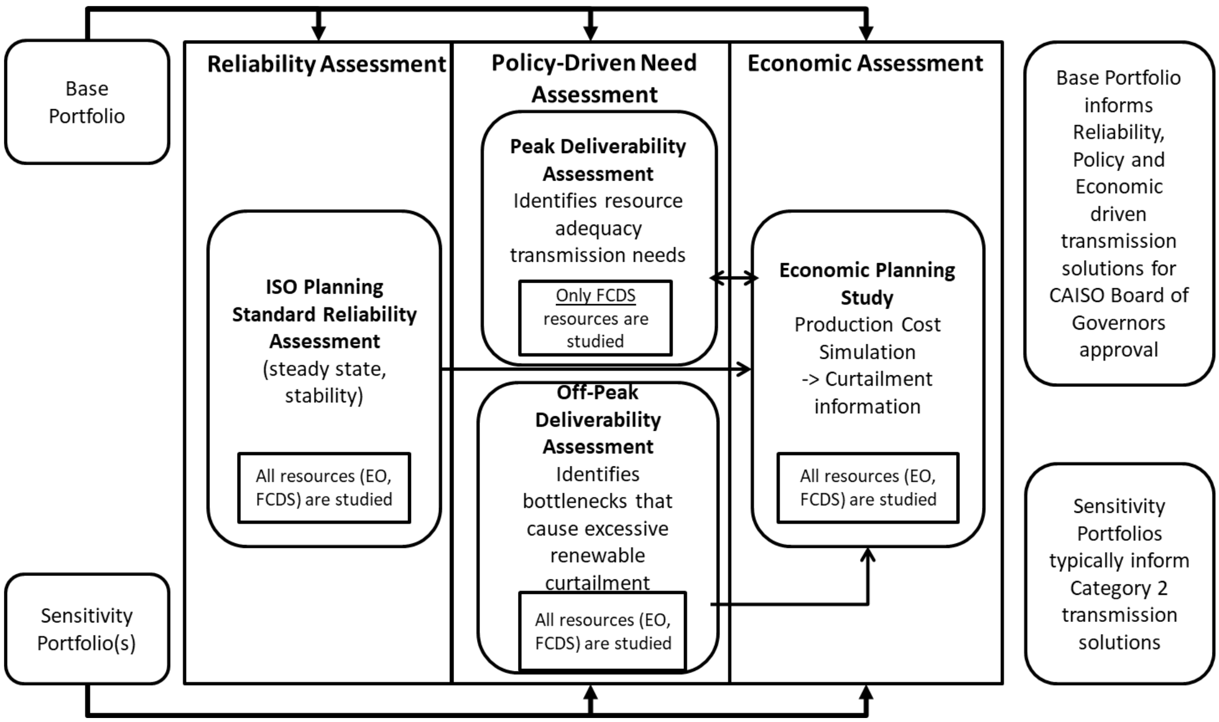
The CAISO and the CPUC have a memorandum of understanding under which the CPUC provides the renewable resource portfolio or portfolios for CAISO to analyze in the CAISO's annual TPP. The CPUC adopted the integrated resource planning (IRP) process designed to ensure that the electric sector is on track to help the State achieve its greenhouse gas (GHG) reduction target, at least cost, while maintaining electric service reliability and meeting other State goals.

3.2 Study methodology and components

The policy-driven assessment is an iterative process comprised of three types of technical studies as illustrated in Figure 3.2-1.

These studies are geared towards capturing the impact of renewable build out on transmission infrastructure, identifying any required upgrades and generating transmission input for use by the CPUC in the next cycle of portfolio development.

Figure 3.2-1: Policy-driven assessment methodology and study components



Reliability assessment

The policy-driven reliability assessment is used to identify constraints that need to be modeled in production cost simulations in order to capture the impact of the constraints on renewable curtailment caused by transmission congestion. The reliability assessment component of the policy-driven assessment is covered by the reliability assessment described in Section 2 and the off-peak deliverability assessment that is performed in accordance with the deliverability methodology as described below.

On-peak deliverability assessment

The on-peak deliverability test is designed to ensure portfolio resources selected with full capacity deliverability status (FCDS) are deliverable and can count towards meeting resource adequacy needs. The assessment examines whether sufficient transmission capability exists to transfer generation from a given sub-area to the aggregate of CAISO control area load when the generation is needed most. The CAISO performs the assessment in accordance with the on-peak deliverability assessment methodology[55].

[55] https://www.caiso.com/documents/on-peak-deliverability-assessment-methodology.pdf

Off-peak deliverability assessment

The off-peak deliverability test is performed to identify potential transmission system limitations that may cause excessive renewable energy curtailment. The CAISO performs the assessment in accordance with the off-peak deliverability assessment methodology.[56]

Production cost model simulation (PCM) study

Production cost models for the base and sensitivity renewable portfolios will be developed and simulated to identify renewable curtailment and transmission congestion in the CAISO Balancing Authority Area. The PCM for the base portfolio is used in both the policy-driven and economic assessments. The PCM for the sensitivity portfolios is used in the policy assessment only. The details of the PCM assumptions and study methodology are set out in chapter 4.

3.3 Resource portfolios

Draft Editorial Note:

Section 3.3 will be updated in the Final Study Plan pending the adopted decision from the CPUC for the 2025-2026 TPP Assumptions.

The CPUC adopts resource portfolios annually as part of its Integrated Resource Planning (IRP) process as a key input to the CAISO's transmission planning process. The CPUC issued Proposed Decision (PD) Revision 1[57] recommending transmittal of the base case portfolio and a sensitivity portfolio with a greater volume of long lead-time (LLT) resources mainly geothermal, long-duration energy storage (LDES) and offshore wind (OSW) for use in the 2025-2026 TPP.

The portfolios are comprised of in-development resources, which have been contracted for or have recently come online, and the incremental generic resources that are selected to achieve policy and reliability targets. The CAISO will model the new baseline and in-development resources in policy-driven study cases in accordance with the data provided by the CPUC. The CAISO may supplement the data with information regarding contracted resources and resources that are under construction as of March 2025.

The portfolios are designed to reduce statewide yearly GHG emissions from the electric sector to 25 MMT by 2035. They are developed with updated assumptions from California Energy Commission's 2023 Integrated Energy Policy Report demand forecast. The base portfolio is comprised of in-development resources, IRPs submitted by load serving entities (LSEs) in November 2022, and additional generic resources that are selected to achieve the policy and

56 http://www.caiso.com/Documents/Off-PeakDeliverabilityAssessmentMethodology.pdf

57 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M557/K045/557045217.pdf By the time of this draft study plan, the final decision has not been voted and approved. Will update with final decision in the final study plan.

reliability targets. The sensitivity portfolio is intended to help study the appropriate transmission development to support the LLT resources called for in D.24-08-064. The portfolio data is available on the CPUC website and includes:

- Proposed Decision Modeling Assumptions for the 2025-2026 Transmission Planning Process[58]
- The proposed busbar mapping dashboards for the base[59] and sensitivity[60] portfolios
- Updated Baseline Reconciliation and In-development resources[61]
- Updated Commercial Interest analysis from CAISO's interconnection queue[62]

In the current planning cycle, the ISO policy driven assessment will be based on the 2035 and 2040 scenarios.

The portfolios are comprised of biomass/biogas, geothermal, solar, in-state, out-of state and offshore wind resources, battery and long duration energy storage. The portfolios consist of resources with Full Capacity (FC) and Energy Only (EO) deliverability status. While both FC and EO resources will be modeled in reliability, off-peak deliverability and economic assessments, only FC resources will be modeled in the on-peak deliverability assessment. In the policy driven deliverability assessment, the ISO will model OOS resources on new transmission at the injection points near the ISO border as identified by the CPUC. OOS resources on existing transmission will be modeled at the resource locations identified by the CPUC. The resources will be dispatched based on the deliverability assessment resource output assumptions provided in Section 3.5.

Table 3.3-1 shows the composition of the base and sensitivity portfolio by resource type for 2035. The 2040 base and sensitivity portfolio composition is shown in Table 3.3-2. The breakdown between FC and EO resources within the portfolios are included in these tables.

58 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/assumptions-for-the-2025-2026-tpp/modeling_assumptions_25-26tpp_pd_2025-01-15.pdf

59 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/assumptions-for-the-2025-2026-tpp/full-dashboard_25-26tpp_basecase_pd.xlsx

60 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/assumptions-for-the-2025-2026-tpp/full-dashboard_25-26tpp_lltsens_2025-01-10.xlsx

61 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/assumptions-for-the-2025-2026-tpp/baselinereconcile_25-6tpp_pdupdate.xlsx

62 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/assumptions-for-the-2025-2026-tpp/mappingcifrom_caisoqueue11-25-2024.xlsx

Table 3.3-1: 2035 Base and Sensitivity Portfolio Composition

	Base Portfolio			Sensitivity Portfolio		
Resource Type	**FCDS (MW)**	**EO (MW)**	**Total (MW)**	**FCDS (MW)**	**EO (MW)**	**Total (MW)**
Biomass	171	0	171	171	0	171
Distributed_Solar	0	294	294	0	280	280
Geothermal	1,639	0	1,639	2,139	0	2,139
LDES	1,264	0	1,264	2,975	0	2,975
Li_Battery (4-hour)	16,189	0	16,189	16,189	0	16,189
Li_Battery (8-hour)	2,593	0	2,593	2,137	0	2,137
Offshore Wind	4,531	0	4,531	7,555	0	7,555
OOS Wind	9,000	0	9,000	7,000	0	7,000
Solar	5,994	13,546	19,539	4,937	12,461	17,398
Wind, Onshore	6,739	1,156	7,895	5,969	954	6,923
TOTAL	**48,120**	**14,996**	**63,115**	**49,072**	**13,695**	**62,767**

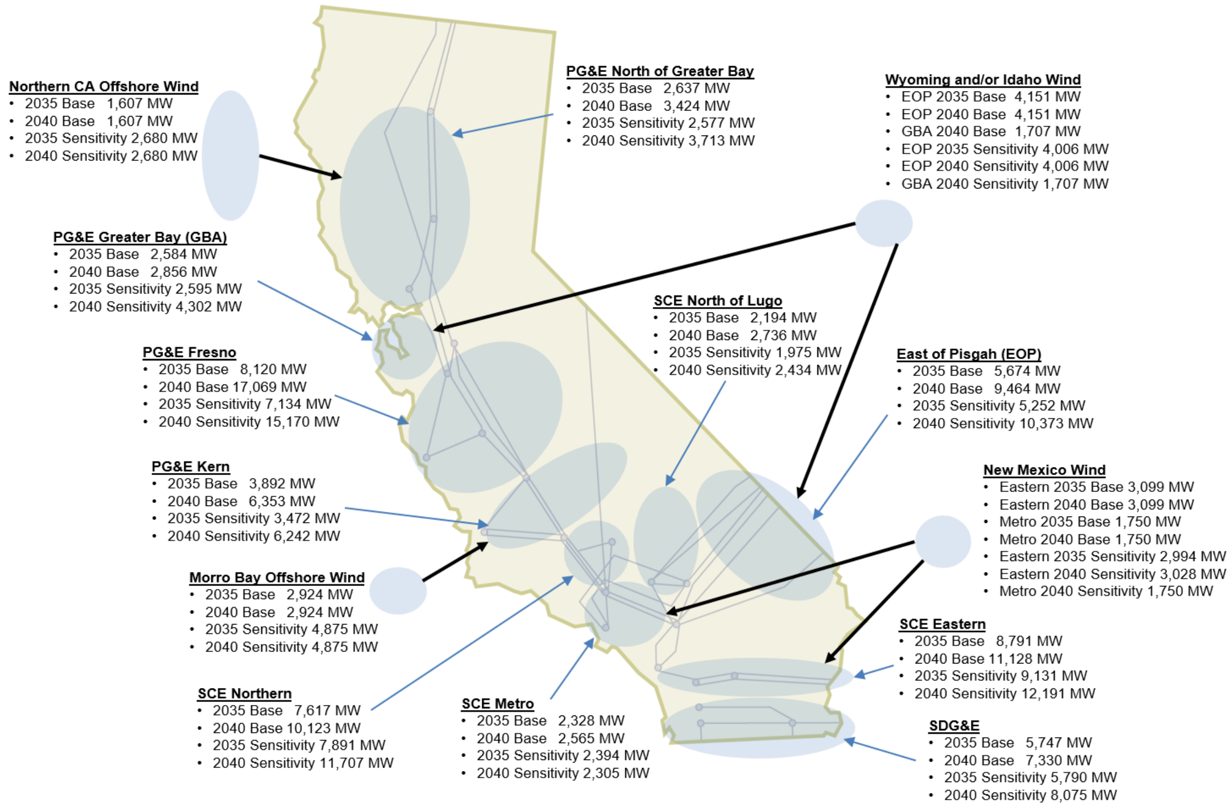
Table 3.3-2: 2040 Base and Sensitivity Portfolio Composition

	Base Portfolio			Sensitivity Portfolio		
Resource Type	**FCDS (MW)**	**EO (MW)**	**Total (MW)**	**FCDS (MW)**	**EO (MW)**	**Total (MW)**
Biomass	171	0	171	171	0	171
Distributed_Solar	0	294	294	0	294	294
Geothermal	1,639	0	1,639	2,139	0	2,139
LDES	1,264	0	1,264	2,785	0	2,785
Li_Battery (4-hour)	16,189	0	16,189	16,189	0	16,189
Li_Battery (8-hour)	11,770	0	11,770	10,195	0	10,195
Offshore Wind	4,531	0	4,531	7,555	0	7,555
OOS Wind	10,707	0	10,707	10,491	0	10,491
Solar	14,229	30,370	44,598	10,691	27,431	38,122
Wind, Onshore	6,739	1,156	7,895	6,252	987	7,239
TOTAL	**67,239**	**31,820**	**99,058**	**66,468**	**28,712**	**95,181**

The 2025-2026 TPP portfolios have no gas plant retirements in the TPP model years beyond the assumed retirements included in the 2024-2025 TPP modeling baseline, which are not reflected in the portfolio summaries and mapping results. In summary, those baselines retirements are all the gas once-through cooling (OTC) plants (~3.7 GW) and assumed linear phaseout of in front of the meter combined heat and power plants (CHP) from 2031-2040, with all 1,964 MW CHPs assumed retired by 2040. CPUC staff recommend assuming the same CHP plants identified for the 2024-2025 TPP 10-year portfolios are also retired in the 2025-2026 TPP 10-year potfolio and the full CHP list is retired for the 2040 portfolios.

A geographical depiction of the 2035 and 2040 Base and Sensitivity portfolios are shown below in Figure 3.3-1 which includes the Offshore and Out-of-State wind brought into their respective areas.

Figure 3.3-1: 2035 and 2040 Base and Sensitivity Portfolios by Area



As part of the bus bar mapping process, CPUC utilizes estimated transmission capability information provided by the ISO to calculate transmission capability usage and exceedance of mapped resources across all identified transmission constraints. Table 3.3-3 and Table 3.3-4 provide CPUC's assessment of transmission capability exceedances of known on-peak and off-peak deliverability constraints by the 2035 and 2040 base portfolio, respectively[63].

[63] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/assumptions-for-the-2025-2026-tpp/full-dashboard_25-26tpp_basecase_pd.xlsx Tabs '2035_Exceedance_Summmary' and '2040_Exceedance_Summary'.

Table 3.3-3: CPUC's assessment of 2035 base portfolio transmission capability exceedances

Base Case (2035) Tx Constraint Exceedances		Constraint's White Paper		FCDS Resources Mapped (In-Dev & Generic)**				EODS Resources Mapped**		Calculated Largest On-peak Exceedance	Calculated Off-peak Exceedance	White Paper Upgrade Info		CPUC staff estimated likelihood of being triggered
CAISO Zone	Constraint Name	On-Peak Capability (MW)	Off-Peak Capability (MW)	Onshore & Offshore Wind (MW)	Solar (MW)	Storage (MW)	Biomass & Geothermal (MW)	Onshore Wind (MW)	Solar (MW)			Capability Increase (MW)	Estimated Cost (millions)	
PG&E North of Greater Bay	Collinsville-Tesla 500 kV Line	3,379	7,706	3,733	75	1,263	275	285	574	(600)	None	8,645	$ 2,852	High
	Carberry-Round Mountain 230kV Line	15	15	200	-	-	17	6	-	(102)	(115)	26	$ 180	High
	Bellota-Weber 230kV Line	1,661	2,539	411	436	1,599	84	93	947	(293)	None	460	$ 400	Low
PG&E Greater Bay	Windmaster-Delta pumps 230 kV Line	546	3,673	416	25	1,140	57	187	289	(862)	None	6,034	$ 417	Low
	Birds Landing-Contra Costa 230kV Line	656	1,176	333	75	527	151	140	423	(199)	None	1,766	$ 700	Low
PG&E Fresno	Chowchilla-Le grand 115kV Line	-	158	320	125	242	6	70	214	(427)	(39)	1,211	$ 550	High
	Borden-Storey #1 230kV line	412	780	320	455	1,113	6	70	1,061	(935)	None	1,247	$ 50	High
SCE North of Lugo	Control to Inyokern Area	-	120	-	-	-	13	-	-	(13)	None	186	$ 329	High
	South of Kramer Area	456	1,190	180	314	411	17	32	300	(96)	None	N/A	N/A	Medium
SCE Eastern	Eagle Mountain Constraint	-	392	-	-	310	530	-	290	(840)	(51)	600	$ 1,182	High
East of Pisgah	Lugo-Victorville Area	10,105	12,605	8,108	1,306	4,247	562	371	4,281	(143)	None	6,800	$ 2,165	Medium
SDG&E	Chicarita 138 kV	224	224	-	-	310	-	-	-	(86)	None	700	$ 100	Low

** Includes amounts from IRP baseline resources not in the White Paper baseline based on COD

Table 3.3-4: CPUC's assessment of 2040 base portfolio transmission capability exceedances

Base Case (2040) Tx Constraint Exceedances		Constraint's White Paper		FCDS Resources Mapped (In-Dev & Generic)**				EODS Resources Mapped**		Calculated Largest On-peak (HSN) Exceedance	Calculated Off-peak Exceedance	White Paper Upgrade Info		CPUC staff estimated likelihood of being triggered
CAISO Zone	Constraint Name	On-Peak Capability (MW)	Off-Peak Capability (MW)	Onshore & Offshore Wind (MW)	Solar (MW)	Storage (MW)	Biomass & Geothermal (MW)	Onshore Wind (MW)	Solar (MW)			Capability Increase (MW)	Estimated Cost (millions)	
PG&E North of Greater Bay	Collinsville-Tesla 500 kV Line	3,379	7,706	3,733	430	2,163	275	285	1,224	(1,553)	None	8,645	$ 2,852	High
	Carberry-Round Mountain 230kV Line	15	15	200	-	-	17	6	-	(102)	(115)	26	$ 180	High
	Bellota-Weber 230kV Line	1,661	2,539	411	2,088	2,199	84	93	2,857	(1,141)	None	460	$ 400	High
PG&E Greater Bay	Windmaster-Delta pumps 230 kV Line	546	3,673	416	45	1,465	57	187	419	(1,190)	None	6034*	$ 417	High
	Tesla-Tracy-Pump 230 kV line #2	4,574	10,136	2,632	101	2,835	157	220	986	(39)	None	3521*	-	Low
	Tesla-Bellota 230 kV line	3,154	4,254	2,688	258	2,722	150	256	1,224	(1,391)	None	300	$ 1,700	High
	Contra Costa 230kV Line	656	1,176	333	330	792	151	140	903	(503)	None	1,766	$ 700	Low
PG&E Fresno	Gates 500/230kV TB #12	5,406	3,581	780	4,198	4,360	16	70	7,542	None	(1,708)	14,825*	$ 35	Medium
	Gates 500/230kV TB #11	5,337	5,027	780	4,658	4,618	30	70	8,443	(400)	(1,079)	10,038*	-	Medium
	Tranquility-Helm 230kV Line	2,921	2,777	320	2,808	2,849	8	70	4,726	(517)	(497)	2,274	$ 1,500	Medium
	Chowchilla-Le grand 115kV Line	-	158	320	675	457	6	70	844	(724)	(497)	1,211	$ 550	High
	Schindler 115/70kV TB #1	-	50	-	300	20	-	-	30	(65)	(191)	3,160	$ 370	High
	Borden-Storey #1 230kV line	412	780	320	1,655	1,743	6	70	2,791	(1,745)	(1,161)	1,247	$ 50	High
	Oro Loma-El Nido 115kV Line	528	308	150	275	260	6	50	636	None	(240)	3,192	$ 330	Low
	Mustang-Henrietta 230 kV line	5,581	5,617	3,187	3,543	3,246	7	50	6,444	(821)	(2,089)	2,479	$ 830	High
SCE North of Lugo	Control to Inyokern Area	-	120	-	-	-	13	-	-	(13)	None	186	$ 329	High
	South of Kramer Area	456	1,190	180	314	411	17	32	300	(96)	None	N/A	N/A	Medium
	Calcite to Lugo Area	297	552	150	300	422	-	-	804	(237)	(180)	1,046	$ 239	High
SCE Eastern	Eagle Mountain Constraint	-	392	-	-	530	310	-	290	(840)	(51)	600	$ 1,182	High
East of Pisgah	Sloan Canyon - Eldorado 500 kV constraint	4,032	4,302	1,660	1,566	2,555	562	50	3,445	(216)	None	N/A	N/A	Medium
	Lugo-Victorville Area	10,105	12,605	8,302	2,854	6,202	562	177	8,421	(2,393)	None	6,800	$ 2,165	High
SDG&E	Chicarita 138 kV	224	224	-	-	310	-	-	-	(86)	None	700	$ 100	Low

*Same upgrades for two of the exceeded constraints

** Includes amounts from IRP baseline resources not in the White Paper baseline based on COD

3.3.1 Approved Non-CPUC Jurisdictional Integrated Resource Plans

As a continued effort to coordinate with the non-CPUC jurisdictional entities to incorporate their approved IRP into the CAISO TPP, the CAISO sent out a non-CPUC jurisdictional IRP resource mapping workbook to the entities to gather their integrated resource planning information on October 30, 2024. By January 15, 2025, the CAISO received data submittal and approved IRP documents from the following Publically Owned Utilities (POUs): Anaheim Public Utilities (APU), Riverside Public Utilities (RPU), Pasadena Water and Power (PWP), Vernon Public Utilities (VPU), Northern California Power Agency (NCPA), Silicon Valley Power (SVP), Colton Electric Utility (CEU) and Valley Electric Association (VEA).

All POU resource data provided that is in an approved IRP or a document approved by their senior leadership will be included in the models for the ISO TPP analysis. However, the resource portfolios provided by the CPUC based on the CPUC IRP, already include placeholder resources to meet the POU load. In many cases the exact same resources have already been modeled, so those resources just need to be transferred from the CPUC portfolio to the POU portfolio. Some POUs also identified certain amounts and types of generic resources the entities planned to procure, but in some cases, no specific substations were identified. For those generic resouces, the CAISO will transfer the same amounts and types of resources from CPUC generic portfolio to the POU portfolio. In cases where no CPUC portfolio is mapped to the same or nearby locations, the CAISO will transfer CPUC resources at locations that are behind the same constraints to the POU portfolio.

Table 3.3-5: Cumulative New Resources Included in Non-CPUC Jurisdictional IRP Plan[64]

Resource Type	2026	2027	2028	2029	2030	2035	2040	2045
Natural Gas								
Geothermal		35	35	35	85	95	106	126
Biomass								
Hydrogen Conversion								
Wind-NorCal								
Wind-SoCal	330	370	370	370	380	380	390	430
Wind-WY								
Wind-PNW								
Wind-ID								
Wind-NM	125	125	125	125	125	125	125	125
Offshore Wind							10	10
Solar-NorCal		10	170	170	170	170	170	200
Solar-SoCal	224	293	404	404	814	1010	1110	1175
Li-ion Battery (4 hr)	300	370	849	1059	1707	1772	2202	2225
Li-ion Battery (8 hr)								
Pumped Hydro Storage (12 hr)								
Other LDES (8-24 hr)								
H2 Fuel Cell					35	35	35	75
Shed Demand Response								
Gas Capacity Not Retained	-108	-283	-337	-337	-585	-585	-890	-890
Total	**871**	**920**	**1616**	**1826**	**2731**	**3002**	**3258**	**3476**

64 The baseload renewable and/or carbon-free generic resource studied in RPU's 2023 IRP for planning purposes is not included in the table. The resource supplies 50 MW in 2034, an additional 60 MW in 2038 and additional 20 MW in 2043

Table 3.3-6: Non-CPUC Jurisdictional IRP Resources Transferred from CPUC Portfolio

POU	CAISO Interconnection Area	Substation	Voltage	Resource Type	Transfer from CPUC Portfolio	2035			2040		
						FCDS	EODS	Total	FCDS	EODS	Total
APU	SCE Eastern	Colorado River	230	Solar	Baseline/In-development	-	100	100	-	100	100
APU	SCE Metro	Mira Loma	230	Li_Battery (4-hour)	Generic	300	-	300	300	-	300
CEU	SCE Eastern	Colorado River	230	Solar	Baseline/In-development		20	20		20	20
CEU	PG&E Kern	Arco	230	Solar	Generic		11	11		11	11
CEU	PG&E Kern	Arco	230	Li_Battery (4-hour)	Generic	11		11	11		11
NCPA	PG&E Fresno	Los Banos-Midway #2 500kV line	500	Solar	Generic	150	-	150	150	-	150
NCPA	PG&E Fresno	Los Banos-Midway #2 500kV line	500	Li_Battery (4-hour)	Generic	150	-	150	150	-	150
NCPA	PG&E GBA	Bellota	230	Li_Battery (4-hour)	Generic	200	-	200	200	-	200
PWP	SCE Metro	Goodrich	230	Li_Battery (4-hour)	Generic	25	-	25	25	-	25
PWP	SCE Eastern	Red Bluff	230	Li_Battery (4-hour)	Unaccounted TPD	20	-	20	20	-	20
PWP	SCE Eastern	Red Bluff	230	Solar	Generic	-	39	39	-	39	39
PWP	SCE Eastern	Colorado River	230	Solar	Baseline/In-development	-	50	50	-	50	50
PWP	East of Pisgah	Innovation	230	Li_Battery (4-hour)	Unaccounted TPD	55	-	55	55	-	55
PWP	East of Pisgah	Innovation	230	Solar	Generic	-	105	105	-	105	105
PWP	SCE NOL	Coso	115	Geothermal	Baseline/In-development	10	-	10	10	-	10
PWP	SCE NOL	Coso	115	Geothermal	Generic	10	-	10	10	-	10
PWP	PG&E NGBA	Geysers	115	Geothermal	Generic	25	-	25	25	-	25
RPU	SCE Eastern	Palo Verde	500	OOS Wind	Baseline/In-development	125	-	125	125	-	125
RPU	SCE Northern	Rector	230	Li_Battery (4-hour)	Generic	80	-	80	80	-	80
RPU	SCE NOL	Roadway	115	Li_Battery (4-hour)	Baseline/In-development	50	-	50	50	-	50
RPU	SCE Eastern			Li_Battery (4-hour)	Generic	36	-	36	236	-	236
RPU				Solar	Generic	120	-	120	195	-	195
RPU				Li_Battery (4-hour)	Generic	50	-	50	50	-	50
RPU				Geothermal	Generic	50	-	50	50	-	50
VPU	SCE Eastern	Red Bluff	230	Li_Battery (4-hour)	Unaccounted TPD	20	-	20	20	-	20
VPU	SCE Eastern	Red Bluff	230	Solar	Generic	-	39	39	-	39	39

POU	CAISO Interconnection Area	Substation	Voltage	Resource Type	Transfer from CPUC Portfolio	2035			2040		
						FCDS	EODS	Total	FCDS	EODS	Total
VPU				Wind	Generic	50	-	50	60	-	60
VPU				Solar	Generic	180	-	180	260	-	260
VPU				Li_Battery (4-hour)	Generic	110	-	110	340	-	340
VPU				Offshore Wind	Generic	-	-	-	10	-	10

3.4 Additional Guidance from CPUC regarding the Portfolios

In the PD Modeling Assumptions for the 2025-2026 Transmission Planning Process, CPUC staff have provided the additional guidance below regarding the base portfolios. The ISO will consider this guidance when conducting the policy-driven assessment.

3.4.1 Additional Guidance on the 2025-2026 TPP Base Portfolio

Project Approvals

The transmission utilization analysis conducted in busbar mapping is limited in scope and designed to highlight areas that may require transmission solutions to accommodate resources mapped. Busbar mapping and RESOLVE modeling are not power flow modeling tools and cannot identify with 100% accuracy where transmission is needed and what upgrades are required – that is the role of the full TPP analysis. Therefore, there is uncertainty in what actual transmission may be required by the portfolio mapping results and TPP analysis may identify alternative, less costly upgrades than those assumed in busbar mapping. CPUC staff encourage the CAISO to assess alternative and potentially less costly upgrades particularly for the exceedances discussed in the PD Modeling Assumptions Section 7 where the amount of resources behind the exceedances may not warrant the size and cost of the identified 2024 White Paper upgrades.

If the TPP policy-driven assessment of the base portfolio identifies the need for upgrades, the CAISO would typically recommend those upgrades to the CAISO Board of Governors for approval as policy-driven transmission upgrades. The CAISO retains more flexibility with approval of projects if they are identified only in the reliability assessments, if they are identified as needed for only the 2040 mapping results, and if the estimated build time does not necessitate immediate commencement to meet the identified resource need. CPUC staff will continue to coordinate with CAISO staff through the busbar mapping Working Group. CPUC staff will also be engaged in the CAISO's Transmission Planning Process by providing comments or additional guidance through the TPP stakeholder process.

Additional Analysis of Transmission Needs for Out-of-State and In-state Wind on New Out-of-CAISO Transmission

The 2025-2026 TPP has a significant amount of OOS wind on new transmission in both the 2035 and 2040 model years (9,000 MW and 10,707 MW, respectively). Although the amounts are close to the 9,095 MW in the 2039 model year for the 2024-2025 TPP, this amount of out-of-state wind and the potential transmission solutions have not been studied previously at a detailed level. Only high-level approximate solutions have been identified in the CAISO's two 20-year Transmission Outlooks. Recent portfolios have only had up to 5-6 GW of OOS wind and CPUC and CAISO staff were able to assess potential transmission solutions from several transmission projects that were already in planning and development specifically SWIP-North,SunZia and TransWest. With these projects now already approved and allocated, additional solutions, costs and routes are not well understood and have not been sufficiently studied. In addition to the OOS wind, the 2025-2026 TPP has 1,150 MW of in-state wind mapped to the area of Northern California serviced by NVE system transmission in both 2035 and 2040. Like OOS wind, aside from the still ongoing 2024-2025 TPP, potential transmission solutions have not been previously examined. For both resources, the potential transmission solutions are likely to be large, complex and crossing difficult terrain and multiple BAAs. Additionally, the interconnection points for these resources assumed in the mapping are based only on high-level studies and more optimal and cost-effective alternatives may exist.

Due to these uncertainties, risks and the complexity and cost of potential solutions, CPUC staff recommend CAISO conduct additional analysis on potential transmission solutions for these resources to better understand the options, costs and potential collaborations with other BAAs.

Further CPUC staff recommend requesting the CAISO defer approving any of these potential transmission lines needed for these resources in the 2025-2026 TPP and, as it is impacted, in the 2024-2025 TPP. Specifically, this request refers to the following resources in the 10-year portfolio, in addition to the OOS wind added in the 15-year portfolio:

- 1,500 MW of Wyoming Wind mapped to Eldorado 500 kV not assumed to be utilizing the TransWest line in both the 2035 and 2040 portfolios
- 1,750 MW of New Mexico Wind mapped to Lugo 500 kV in both the 2035 and 2040 portfolios
- 1,150 MW of Northern California Wind mapped to three NVE substations (Hilltop 345 kV and new substations near Leavitt and Madeline) in both the 2035 and 2040 portfolios
- 1,707 MW of Wyoming Wind mapped to Tesla in the 2040 portfolio

Reserve Deliverability for Certain Types of Resources

Certain types of resources have unique value and may become more cost-competitive in the future, but they currently have longer and more difficult development processes, are limited by geographic location and/or may be more expensive. The resources that fully meet these criteria currently are geothermal, biomass, OSW and non-battery LDES. Thus the CPUC requests the

CAISO to reserve deliverability for all of these types of resources in the 2035 portfolio, using the amounts and locations included in the portfolio's busbar mapping results, to the extent consistent with the CAISO tariff and still-ongoing 2023 IPE Track 3 Initiative. These requested amounts are inclusive of the OOS and OSW resource amounts for which the CAISO is already reserving deliverability. The CPUC also requests the CAISO to reserve deliverability for these resources in the results of the 2024-2025 TPP, if transmission solutions or upgrades are identified and approved, and if the resources that are mapped in the 2024-2025 TPP base case are in the same or greater quantities in the 2025-2026 TPP recommended base case.

Considering the amount of in-state and OOS wind in development and in the portfolio that can take advantage of existing or already-approved transmission, the CPUC requests the CAISO to reserve deliverability for a portion of these resources in the TPP, specifically excluding resources mapped as energy only and the mapped resources with potential transmission upgrades identified for further study. Specifically, the CPUC requests the CAISO to reserve deliverability for the approximately 5.7 GW of OOS wind resources that will utilize the new transmission lines already in development or approved (approximately 1.1 GW of Idaho wind, 1.5 GW of Wyoming wind, and 3.1 GW of New Mexico wind).

Alignment with CAISO Queue Resources with Allocated TPD to Preserve Deliverability for Specified Resources

As was done for the 2024-2025 TPP and 2023-2024 TPP, CPUC staff request that the CAISO continue the necessary studies to inform and enable opportunities to provide Maximum Import Capability (MIC) expansion and the development of incremental transmission capacity to support the OOS and long lead-time (LLT) resources mapped in the policy- and reliability-driven base case portfolio, while preserving the existing transmission capacity that has been allocated to other projects earlier in the interconnection queue. The CPUC has identified unaccounted TPD in Table 3.4-1 for study areas that interact with MIC paths that have been expanded, so that the ISO can include this generation along with the portfolio in the Policy study models.

In addition, this year, CPUC staff has identified unaccounted for TPD in Table 3.4-2 that would impact reserving deliverability for the offshore wind mapped to the North Coast to be included in the TPP analysis. Initially, approximately 1,540 MW in 2035 and 960 MW in 2040 have been identified as likely needing to be include in the analysis. The CPUC propose this additional amount of storage resources to be included with the mapped portfolio resources for study in the 2025-2026 TPP, to inform and enable the necessary transmission capacity to support the deliverability of these key OSW resources.

Table 3.4-1: Unaccounted TPD in Key MIC Regions in Base Portfolio[65]

Unaccounted for TPD impacting OOS wind on new transmission and out-of-CAISO geothermal needing MIC in the SCE Eastern and East of Pisgah study areas.			**Awarded TPD in key MIC regions unaccounted for by mapped resources (MW)**	
CAISO Study Area	**Substation**	**Voltage**	**2035**	**2040**
EOP	Gamebird	230	137	-
EOP	Desert View	230	350	100
EOP	Eldorado	230	250	-
EOP	Innovation	230	100	-
EOP	Mohave	500	920	780
EOP	Trout Canyon	230	864	550
EOP	Valley (VEA)	138	40	-
SCE Eastern	Alberhill	500	500	500
SCE Eastern	Cielo Azul	500	638	388
SCE Eastern	Colorado River	230	300	150
SCE Eastern	Delaney	500	450	350
SCE Eastern	Devers	230	146	66
SCE Eastern	Etiwanda	230	400	400
SCE Eastern	Red Bluff	230	810	810
SCE Eastern	Red Bluff	500	500	430
SCE Eastern	Valley (SCE)	500	710	710
SDGE	Hassayampa	500	25	-
		Total (MW)	**7,140**	**5,233**

65 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/assumptions-for-the-2025-2026-tpp/full-dashboard_25-26tpp_basecase_pd.xlsx "Unaccountedfor_TPD" Tab

Table 3.4-2: Unaccounted TPD Impacting OSW Deliverability in Base Portfolio[66]

Unaccounted for TPD impacting North Coast offshore wind deliverability reservation in the North of Greater Bay and Greater Bay study areas.			**Awarded TPD at key buses for North Coast OSW unaccounted for by mapped resources (MW)**	
CAISO Study Area	**Substation**	**Voltage**	**2035**	**2040**
PG&E GBA	Birds Landing	230	50	-
PG&E GBA	Cooley Landing	60	65	50
PG&E NGBA	Cortina	115	116	76
PG&E GBA	Kirker	115	2	2
PG&E GBA	Martin	115	312	162
PG&E GBA	Pittsburg	115	675	500
PG&E GBA	Pittsburg	230	325	250
PG&E NGBA	Tulucay	60	2	2
		Total (MW)	**1,547**	**1,042**

Out-of-CAISO Resources and Maximum Import Capability (MIC)

The 2025-2026 TPP base case portfolio, in addition to the almost 10,700 MW of OOS wind on new transmission by 2040, has a significant amount of geothermal mapped to IID and areas in Nevada and Utah beyond the CAISO's Balancing Area. As was done in previous TPP, busbar Working Group staff specified in the Mapping Dashboard the out-of-CAISO transmission and MIC assumptions for these resources including whether the resources should be treated by CAISO in TPP analysis as using existing MIC allocations or require MIC expansion. For all the OOS wind on new transmission and geothermal resources, Working Group staff identified the resources as requiring MIC expansion. Full details of the out-of-CAISO resources can be found on the "Out-of-CAISO_Summary" tab of the PD Mapping Dashboard.

Battery Storage-Specific Transmission Upgrades and Battery Storage as Transmission Upgrade Alternatives

As with past TPP portfolio transmittals, CPUC staff acknowledge that, in some cases, more information is needed to understand the full impacts of the battery mappings, particularly in LCR areas, before new transmission projects are identified by the CAISO as needed. Battery mappings are relatively flexible and accordingly, CAISO staff should consult CPUC staff before moving forward with any new policy-driven transmission upgrades associated specifically with storage mapping in this planning cycle. Additionally, to the extent that storage resources are required for mitigation of transmission issues identified in the CAISO's 2024-2025 Transmission Plan, CPUC staff would expect to coordinate with CAISO to enable small adjustments in the

[66] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/assumptions-for-the-2025-2026-tpp/full-dashboard_25-26tpp_basecase_pd.xlsx "Unaccountedfor_TPD" Tab

CPUC’s mapping of storage resources to allow for the inclusion of this storage in the CAISO’s analysis of the 2025-2026 TPP portfolio.

3.5 Deliverability assessment methodology

3.5.1 On-peak deliverability assessment

On-peak deliverability assessment is performed under two distinct system conditions – the highest system need (HSN) scenario and the secondary system need (SSN) scenario. The HSN scenario represents the period when the capacity shortage is most likely to occur. In this scenario, the system reaches peak sale with low solar output. The highest system need hours represent the hours ending 19 to 22 in the summer months.

The secondary system need scenario represents the period when capacity shortage risk increases if variable resources are not deliverable during periods when the system depends on their high output for resource adequacy. In this scenario, the system load is modeled to represent the peak consumption level and solar output is modeled at a significantly higher output. The secondary system need hours are hours ending 15 to 18 in the summer months.

The ISO performes on-peak deliverability assessment for both HSN and SSN scenarios. For each scenario and each portfolio, the ISO developes a master deliverability assessment base case that models all FCDS portfolio resources. Key assumptions of the deliverability assessment are described below.

Transmission

The ISO will model the same transmission system as in the corresponding 2035 and 2040 peak load base cases that are used in the reliability assessment performed as part of the current transmission planning process.

System load

The ISO will model a coincident 1-in-5 year peak for the ISO balancing authority area load in the HSN base case. Pump load is dispatched within the expected range for summer peak load hours. The load in the SSN base case is adjusted from the HSN case to represent the net customer load at the time of forecasted peak consumption.

Maximum resource output (Pmax) assumptions

Pmax in the on-peak deliverability assessment represents the resource-type specific maximum resource output assumed in the deliverability assessment. For non-intermittent resources, the same Pmax is used in the HSN and SSN scenarios. The the highest summer month NQC in the last three years is used as Pmax for existing non-intermittent generating units. For non-intermittent generators, the Pmax is set according to the interconnection request and the generators’ deliverability status. For non-intermittent generic portfolio resources, the FCDS capacity provided in the portfolio is used as the Pmax. For energy storage resources, the Pmax is set to the 4-hour discharging capacity in the HSN scenario and 50% of the 4-hour discharging capacity in the SSN scenario, limited by the requested maximum output from the resource, if applicable. For hybrid projects, the study amount for each technology is first calculated separately. Then the total study amount among all technologies is based on the sum of each technology, but limited by the requested maximum output of the generation project.

Intermittent resources are modeled in the HSN scenario based on the output profiles during the highest system need hours. A 20% exceedance production level for wind and solar resources during these hours sets the Pmax tested in the HSN deliverability assessment. In the SSN scenario, intermittent resources are modeled based on the output profiles during the secondary system need hours. 50% exceedance production level for wind and solar resources during the hours sets the Pmax tested in the SSN deliverability assessment.

The maximum resource output (Pmax) assumptions used in HSN and SSN deliverability assessment are shown in Table 3.5-1

Table 3.5-1: Maximum resource output tested in the deliverability assessment

Area	**HSN**				**SSN**			
	SDG&E	**SCE**	**PG&E**	**VEA**	**SDG&E**	**SCE**	**PG&E**	**VEA**
Solar	6%	13%	15%	8%	71%	80%	71%	66%
Wind	35%	48%	50%	48%	10%	17%	19%	17%
Out-of-state Wind (NM, WY, ID)	67%				35%			
Off-shore Wind	83%				45%			
Energy Storage	100% or 4-hour equivalent if duration is < 4-hour				50% or 4-hour equivalent if duration is < 4-hour			
Non-Intermittent resources	NQC or 100%							

Import Levels

For the HSN scenario, the net scheduled imports at all branch groups as determined in the latest annual Maximum Import Capability (MIC) assessment set the imports in the study. Approved MIC expansions will be added to the import levels. Historically unused Existing Transmission Contracts (ETC's) crossing control area boundaries are modeled as zero MW injections at the tie point, but available to be turned on at remaining contract amounts for screening analysis. MIC expansions needed to accommodate portfolio resources are added to the import levels. Valid MIC expansion requests are similarly modeled but are not allowed to trigger transmission upgrades.

For the SSN scenario, the hour with the highest total net imports among all secondary system need hours from the latest MIC assessment data will be selected. Net scheduled imports for the hour set the imports in the study. Approved and requested MIC expansions and MIC expansions needed to accommodate portfolio resources are modeled similar to the HSN scenario.

3.5.2 General On-peak deliverability assessment procedure

The main steps of the California ISO on-peak deliverability assessment procedure are described below.

Screening for Potential Deliverability Problems Using DC Power Flow Tool

A DC transfer capability/contingency analysis tool is used to identify potential deliverability problems. For each analyzed facility, an electrical circle is drawn which includes all generating units including unused Existing Transmission Contract (ETC) injections that have a 5% (or 10% for 500 kV lines) or greater:

Distribution factor (DFAX) = (Δ flow on the analyzed facility / Δ output of the generating unit) *100%

or

Flow impact = (DFAX * Full Study Amount / Applicable rating of the analyzed facility) *100%.

Load flow simulations are performed, which study the worst-case combination of generator output within each 5%/10% Circle.

Verifying and Refining the Analysis Using AC Power Flow Tool

The outputs of capacity units in the 5%/10% Circle are increased starting with units with the largest impact on the transmission facility. No more than 20 units are increased to their maximum output. In addition, no more than 1,500 MW of generation is increased. All remaining generation within the Control Area is proportionally displaced, to maintain a load and resource balance.

When the 20 units with the highest impact on the facility can be increased more than 1,500 MW, the impact of the remaining amount of generation to be increased is considered using a Facility Loading Adder. The Facility Loading Adder is calculated by taking the remaining MW amount available from the 20 units with the highest impact times the DFAX of each unit. An equivalent MW amount of generation with negative DFAX will also be included in the Facility Loading Adder, up to 20 units. Negative Facility Loading Adders should be set to zero.

The ISO's on-peak deliverability assessment simulation procedure as implemented in PowerGem's Transmission Adequacy & Reliability Assessment (TARA) software will be used to perform the policy-driven on-peak deliverability assessment.

Mitigation Alternatives

Potential mitigation alternatives that will be considered to address on-peak deliverability constraints include but are not limited to Remedial Action Schemes (RAS) and other operating solutions, reduction of portfolio battery storage behind the constraints and transmission upgrades. Transmission upgrades identified for the base portfolio under HSN scenario will be recommended as policy driven upgrades. Transmission upgrades identified for the base portfolio under SSN scenario will go through a comprehensive economic, policy and reliability benefit analysis to be considered for approval as a policy or economic upgrade.

3.5.3 Off-peak deliverability assessment

The general off-peak deliverability assessment system study conditions are intended to capture a reasonable scenario for the load, generation, and imports that stress the transmission system, but not coinciding with an oversupply situation. By examining the renewable curtailment data from 2018, a load level of about 55% to 60% of the summer peak load and an import level of about 6000 MW was selected for the off-peak deliverability assessment.

The production of wind and solar resources under the selected load and import conditions varies widely. The production duration curves for solar and wind were examined. The production level under which 90% of the annual energy was selected to set the outputs to be tested in the off-peak deliverability assessment. The dispatch of the remaining generation fleet is set by examining historical production associated with the selected renewable production levels. The hydro dispatch is about 30% of the installed capacity and the thermal dispatch is about 15%. All energy storage facilities are assumed offline.

The dispatch assumptions discussed above apply to both full capacity and energy-only resources. However, depending on the amount of generation in the portfolio, it may be impossible to balance load and resources under such conditions with all portfolio generation dispatched. The dispatch assumptions are applied to all existing, under-construction and contracted generators first, then some portfolio generators if needed to balance load and resources. This establishes a system-wide dispatch base case or master base case that is the starting case for developing each of the study area base cases to be used in the off-peak deliverability assessments. Table 3.5-2 summarizes the generation dispatch assumptions in the master base case.

Table 3.5-2: ISO System-Wide Generator Dispatch Assumptions

	Dispatch Level
Wind	44%
Solar	68%
Battery storage	0%
Hydro	30%
Thermal	15%

The off-peak deliverability assessment may be performed for each study area separately. The study areas in general are the same as the reliability assessment areas in generation interconnection studies.

Study area base cases are created from the system-wide dispatch base case. All generators in the study area, existing or future, are dispatched to a consistent output level. In order to capture local curtailment, the renewable dispatch is increased to the 90% energy level for the study area, which is higher than the system-wide 90% energy level. The study area 90% energy level was determined from representing individual plants in different areas. For out-of-state and off-shore wind, the dispatch values are based on data obtained from NREL for the PCM model.

If the renewables inside the study area are predominantly wind resources (more than 70% of total study area capacity), wind resource dispatch is increased as shown in Table 3.5-3. All the solar resources in the wind pocket are dispatched at the system-wide level of 68%. If the renewables inside the study area are not predominantly wind resources, then the dispatch assumptions in Table 3.5-4 are used. The dispatch assumptions for out-of-state and off-shore wind used in the current study are provided in Table 3.5-5.

Table 3.5-3: Local Area Solar and Wind Dispatch Assumptions in Wind Area

	Wind Dispatch Level	Solar Dispatch Level
SDG&E	69%	68%
SCE	64%	
PG&E	63%	

Table 3.5-4: Local Area Solar and Wind Dispatch Assumptions in Solar Area

	Solar Dispatch Level	Wind Dispatch Level
SDG&E	79%	44%
SCE	77%	
PG&E	79%	

Table 3.5-5: Additional Local Area Dispatch Assumptions

Resource	Dispatch Level
Offshore Wind	100%
New Mexico Wind	67%
Wyoming Wind	67%

As the generation dispatch increases inside the study area, the following resource adjustment can be performed to balance the loads and resources:

- Reduce new generation outside the study area (staying within the Path 26, 4000 MW north to south, and 3000 MW south to north limits)
- Reduce thermal generation inside the study area
- Reduce imports
- Reduce thermal generation outside the study area.

Once each study area case has been developed, a contingency analysis is performed for normal conditions and selected contingencies:

- Normal conditions (P0)
- Single contingency of transmission circuit (P1.2), transformer (P1.3), single pole of DC lines (P1.5)
- Multiple contingency of two adjacent circuits on common structures (P7.1) and loss of a bipolar DC line (P7.2).

For overloads identified under such dispatch, resources that can be re-dispatched to relieve the overloads are adjusted to determine if the overload can be mitigated:

- Existing energy storage resources are dispatched to their full four-hour charging capacity to relieve the overload
- Thermal generators contributing to the overloads are turned off
- Imports contributing to the overloads are reduced to the level required to support out-of-state renewables in the portfolios.

Mitigation options will be developed to address the remaining overloads after the re-dispatch. Generators with 5%/10% or higher distribution factor (DFAX) on the constraint are considered contributing generators. The distribution factor is the percentage of a particular generation unit's incremental increase in output that flows on a particular transmission line or transformer under the applicable contingency condition when the displaced generation is spread proportionally, across all dispatched resources available to scale down output proportionally. Generation units are scaled down in proportion to the dispatch level of the unit.

Mitigation Alternatives
Potential alternatives that will be considered to address off-peak deliverability constraints include, but are not limited to, Remedial Action Schemes (RAS) and other operating solutions, dispatching portfolio battery storage behind the constraints in charging mode and transmission upgrades. Transmission upgrades identified to address off-peak deliverability constraints will be considered as candidates for a more thorough evaluation using production cost simulation

3.6 Coordination with GIP

According to tariff Section 24.4.6.5 and in order to better coordinate the development of potential infrastructure from transmission planning and generation interconnection processes the CAISO may coordinate the TPP with generator interconnection studies. In general, Network Upgrades and associated generation identified during the Interconnection Studies will be evaluated and possibly included as part of the TPP. The details of this process are described below.

Generator Interconnection Network Upgrade Criteria for TPP Assessment

Beginning with the 2012-2013 planning cycle, generator interconnection Network Upgrades may be considered for potential modification in the TPP if the Network Upgrade:

- Consists of new transmission lines 200 kV or above and have capital costs of $100 million or more;
- Is a new 500 kV substation that has capital costs of $100 million or more; or
- Has a capital cost of $200 million or more.

Notification of Network Upgrades being assessed in the TPP

The CAISO will publish the list of generator interconnection Network Upgrades that meet at least one of these criteria and have been selected for consideration in TPP Phase 2, if any. The comprehensive Transmission Plan will contain the results of the CAISO's evaluation of the identified Network Upgrades. Network Upgrades evaluated by the CAISO but not modified as part of the comprehensive Transmission Plan will proceed to Generator Interconnection Agreements (GIAs) through the Generator Interconnection and Deliverability Allocation Procedure (GIDAP) and will not be further addressed in the TPP. Similarly, GIP Network Upgrades that meet the tariff criteria but were not evaluated in the TPP will proceed to GIAs through the GIDAP.

All generation projects in the generation interconnection cluster study have the potential to create a need for Network Upgrades. As a result, the CAISO may need to model some or all of these generation projects and their associated transmission upgrades in the TPP base cases for the purpose of evaluating alternative transmission upgrades. However, these base cases will be considered sensitivity base cases in addition to the base cases developed under the Unified Planning Assumptions. These base cases will be posted on the CAISO protected web-site for stakeholder review. Study results and recommendations from these cases will be incorporated in the comprehensive transmission plan.

Transmission Plan Deliverability

Section 8.9 of the GIDAP specifies that an estimate of the generation deliverability supported by the existing system and approved transmission upgrades will be determined from the most recent Transmission Plan. Transmission plan deliverability (TPD) is estimated based on the area deliverability constraints identified in recent generation interconnection studies without considering local deliverability constraints. For study areas in which the TPD is greater than the MW amount of generation in the CAISO interconnection queue, TPD is not quantified. The ISO's latest TPD estimates were published in August 2024[67].

[67] https://www.caiso.com/documents/2024-transmission-plan-deliverability-allocation-report.pdf

4. Economic Planning Study

The CAISO will perform an Economic Planning Study as part of the current planning cycle to identify potential congestion and propose mitigation plans. The study will quantify the economic benefits for the CAISO ratepayers based on Transmission Economic Assessment Methodology (TEAM). Through the evaluation of the congestion and other benefits, and review of the study requests, the CAISO will determine the high priority studies to be conducted during the 2025-2026 transmission planning cycle.

4.1 Renewable Generation

The CPUC adopted the integrated resource planning (IRP) process designed to ensure that the electric sector is on track to help the State achieve its greenhouse gas (GHG) reduction target, at least cost, while maintaining electric service reliability and meeting other State goals.

The CPUC IRP base portfolios are transmitted for the purpose of being studied as part of the reliability, policy-driven, and economic assessments. See Chapter 3 for details regarding the portfolios.

4.2 Congestion and Production Benefit Assessment

Production cost simulation is used to identify transmission congestion and quantify the energy benefit based on TEAM. The production cost model (PCM) will be developed, using the 2034 anchor dataset (ADS) PCM as a starting database[68], based on the same assumptions as the Reliability Assessment and Policy Driven Transmission Plan Analysis with the following exception:

- The 1-in-2 demand forecast will be used in the assessment.

The Economic Planning Study will conduct hourly analysis the 10th planning year through production simulation, and for other planning year as optional if it is needed for providing a data point in the production benefit assessment for transmission project economic justification.

4.3 Study Request

As part of the requirements under the CAISO tariff and Business Practice Manual, Economic Planning Study Requests are to be submitted to the CAISO during the comment period following the stakeholder meeting to discuss this Study Plan. The CAISO will consider the Economic Planning Study Requests as identified in section 24.3.4.1 of the CAISO Tariff.

As part of the requirements under the CAISO tariff and Business Practice Manual, Economic Planning Study Requests were to be submitted to the CAISO during the comment period

[68] The ADS PCM is developed in the Western Interconnection ADS process, which has a two-year cycle.

following the stakeholder meeting to discuss this Study Plan. The CAISO will consider the Economic Planning Study Requests as identified in section 24.3.4.1 of the CAISO Tariff. Table 4.3-2 includes the Economic Planning Study Requests that were submitted for this planning cycle. The CAISO will evaluate these study requests with consideration of current year's transmission planning study results.

Table 4.3-1: Economic study requests

No.	Study Request	Submitted By	Location

Draft Editorial Note:

Table 4.3-1 will be updated based upon the economic study requests received in the comment window following the stakeholder meeting for the draft study plan on February 26.

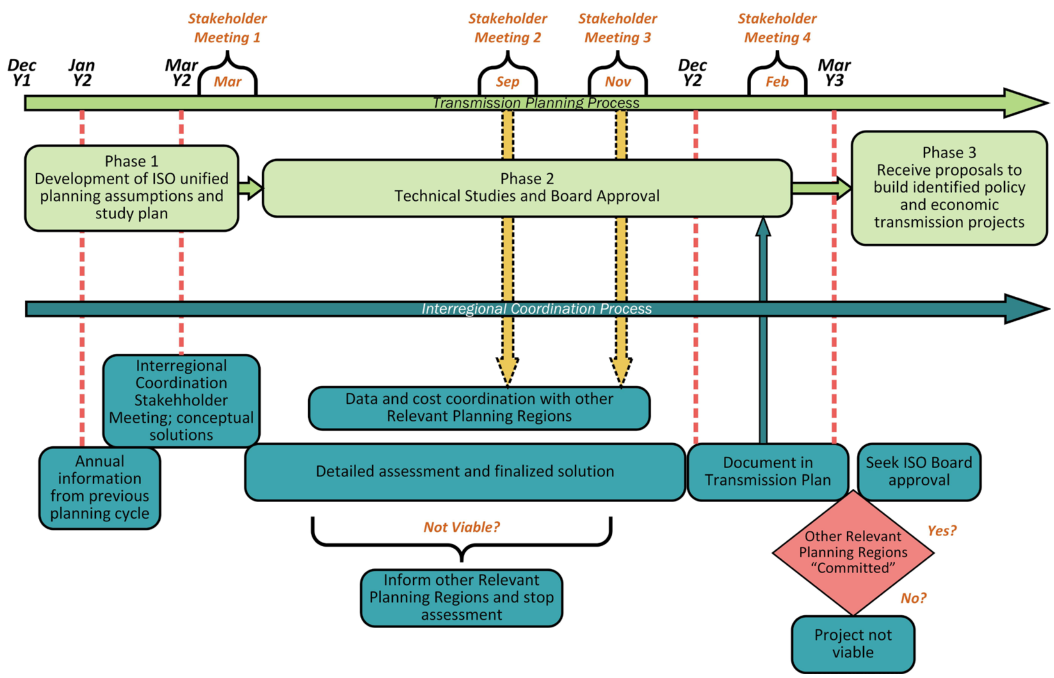
5. Interregional Coordination

During the CAISO's 2025-2026 Transmission Planning Process, the CAISO will, in coordination with the other western planning regions, continue the 2024-2026 interregional transmission coordination cycle. During the odd year of the interregional transmission coordination cycle, the CAISO will complete the following key activities:

- Participate in western planning regions' stakeholder meetings as appropriate
- Generally, based on initial assessments of ITPs in the previous year's TPP cycle, the ISO will determine whether to further evaluate the submitted projects during the odd year of the planning cycle. Specifically, for the 2025-2026 tramission planning process:
    - WestConnect will not evaluate the submitted ITPs to determine if they meet any regional transmission needs because WestConnect has determined that there are no regional transmission needs in its 2024-26 regional planning cycle. As a result the ISO will not be studying submitted ITPs between CAISO and WestConnect in the 2025-2026 transmisison planning process.
    - Northern Grid has yet to make a regional need determination on submitted ITPs and until such time it makes a determination, the ISO does not intend to study the applicable submitted ITPs.
- During the ISO's 2025-2026 TPP, the ISO will, in coordination with the other western planning regions, initiate the 2026-2028 interregional transmission coordination cycle, beginning on January 1, 2026. The submission window will close on March 31, 2026.

Figure 4.3-1 illustrates the interregional coordination process for the odd year of the two year cycle.

Figure 4.3-1 Odd Year Interregional Coordination Process



The CAISO will keep stakeholders informed about its interregional activities through the stakeholder meetings identified in Table 1.1-1. Current information related to the interregional transmission coordination effort may be found on the interregional transmission coordination webpage is located at the following link:

https://www.caiso.com/meetings-events/topics/interregional-transmission-coordination

6. Other Studies

6.1 Local Capacity Requirement Assessment

6.1.1 Near-Term Local Capacity Requirement (LCR)

The local capacity studies focus on determining the minimum MW capacity requirement within each of local areas inside the CAISO Balancing Authority Area. The Local Capacity Area Technical Study determines capacity requirements used as the basis for procurement of resource adequacy capacity by load-serving entities for the following resource adequacy compliance year and also provides the basis for determining the need for any CAISO “backstop” capacity procurement that may be needed once the load-serving entity procurement is submitted and evaluated.

Scenarios

The near-term local capacity studies will be performed for at least 2 years:

- 2026 – Local Capacity Area Technical Study
- 2030 – Mid-Term Local Capacity Requirements

Please note that in order to meet the CPUC deadline for capacity procurement by CPUC-jurisdictional load serving entities, the CAISO will complete the LCR studies approximately by May 1, 2025.

Load Forecast

The latest available CEC load forecast, at the time of base case development, will be used as the primary source of future demand modeled in the base cases. The 1-in-10 load forecast for each local area is used.

Transmission Projects

CAISO-approved transmission projects will be modeled in the base case. These are the same transmission project assumptions that are used in the reliability assessments and discussed in the previous section.

Imports

The LCR study models historical imports in the base case; the same as those used in the RA Import Allocation process

Methodology

A study methodology documented in the LCR manual will be used in the study. This document is posted on CAISO website at:

https://stakeholdercenter.caiso.com/InitiativeDocuments/FinalStudyManual-2026LocalCapacityRequirements.pdf

Tools

GE PSLF and PowerGEM TARA will be used in the LCR study.

Since LCR is part of the overall CAISO Transmission Plan, the Near-Term LCR reports will be posted on the 2025-2026 CAISO Transmission Planning Process webpage.

6.1.2 Long-Term Local Capacity Requirement Assessment

Based on the alignment[69] of the CAISO transmission planning process with the CEC Integrated Energy Policy Report (IEPR) demand forecast and the CPUC Integrated Resource Plan (IRP), the long-term LCR assessment is to take place every two years. The long-time LCR study was performed in the 2024-2025 Transmission Plan and therefore the 2025-2026 transmission planning process will not include a 10 year out study.

6.2 Maximum Import Capability Expansion Requests

Per section 3.2.2.3 of the Transmission Planning Process Business Practice Manual (TPP BPM), requests to perform deliverability studies in order to expand the maximum import capability must be submitted to the CAISO within 2 weeks after the first stakeholder meeting not later than the time that the study plan comments are due. The maximum import capability expansion requests must identify the intertie(s) (branch group(s)) that require expansion. For an LSE the request must include information about existing resource adequacy contracts. For new transmission owners or other market participants the request must include information on contractual arrangements or other evidence of financial commitments the requestor has already made in order to serve load or meet resource adequacy requirements within the CAISO balancing authority area. The quality of the data must be sufficient for the CAISO to make a determination about the validity of such request as available in the Tariff. The CAISO will maintain confidentiality of data provided except for the requestor name, intertie (branch group) the MW quantity and technology of the expansion request.

First the CAISO will evaluate each maximum import capability expansion request in order to establish if the submitting entity meets the criteria listed in the Tariff Section 24.3.5. The descriptions of valid maximum import capability requests as determined by the CAISO will be included in the final study plan. Than the CAISO will coordinate the valid MIC expansion requests with the policy driven MIC expansion and the total of the two will be used to identify all branch groups that do not have sufficient Remaining Import Capability to cover both the valid MIC expansion requests and the policy driven MIC expansion.

The exact calculation of the target expanded MIC can be found in Reliability Requirements Business Practice Manual (RR BPM) section 6.1.3.5 “Deliverability of Imports”.

69 http://www.caiso.com/Documents/TPP-LTPP-IEPR_AlignmentDiagram.pdf

The interrelation between the target expanded MIC and the generation interconnection process can be found in RR BPM section 6.1.3.6 “Modeling Expended MIC Values in GIP”.

Table 6.2-1 includes the valid Maximum Import Capability expansion requests that were submitted for this planning cycle.

Table 6.2-1: Valid Maximum Import Capability expansion requests

No.	Requestor Name	Intertie Name (Scheduling Point)	MW quantity (NQC)	Technology
TBD	TBD	TBD	TBD	TBD

The CAISO has received TBD submittals with requests for MIC expansion. They contained TBD distinct requests.

Based on the CAISO interpretation of the Tariff and the Transmission Planning BPM (TP BPM) requirements TBD distinct requests qualify as valid requests based on the following factors:

1. TBD.

For the following reasons, TBD distict request do not qualify at this time:

1. TBD.

Draft Editorial Note:

Section 6.2 will be updated in the Final Study Plan based upon the MIC Expansion requests received in the comment window following the stakeholder meeting for the draft study plan on February 26.

Important reminder:
In order to avoid the risk of not being able to count a valid RA contract, the CAISO strongly encourages LSEs to first receive the MIC allocation at the branch group of their choice before they sign an external resource (including dynamic schedule and pseudo-ties) to an RA contract. Under the Tariff and RR BPM specified conditions, LSEs have an opportunity to qualify such contracts as New Use Import Commitments in order to receive priority allocation on their choosen intertie for the length of the contract.

6.3 Long-Term Congestion Revenue Rights (LT CRR)

The CAISO is obligated to ensure the continuing feasibility of Long Term CRRs (LT-CRRs) that are allocated by the CAISO over the length of their terms. As such, the CAISO, as part of its annual TPP cycle, shall test and evaluate the simultaneous feasibility of allocated LT-CRRs, including, but not limited to, when acting on the following types of projects: (a) planned or proposed transmission projects; (b) Generating Unit or transmission retirements; (c) Generating Unit interconnections; and (d) the interconnection of new Load. While the CAISO expects that released LT-CRRs will remain feasible during their full term, changes to the interconnected network will occur through new infrastructure additions and/or modifications to existing infrastructure. To ensure that these infrastructure changes to the transmission system do not cause infeasibility in certain LT-CRRs, the CAISO shall perform an annual Simultaneous Feasibility Test (SFT) analysis to demonstrate that all released CRRs remain feasible. In assessing the need for transmission additions or upgrades to maintain the feasibility of allocated LT- CRRs, the CAISO, in coordination with the PTOs and other Market Participants, shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as acceleration or expansion of existing projects, demand-side management, Remedial Action Schemes, constrained-on Generation, interruptible loads, reactive support, or in cases where the infeasible LT- CRRs involve a small magnitude of megawatts, ensuring against the risk of any potential revenue shortfall using the CRR Balancing Account and uplift mechanism in Section 11.2.4 of the CAISO tariff.

6.4 Frequency Response Assessment

As inverter Based Resources (IBR) become an ever higher proportion of the overall energy resource mix it is important to check on the ability of the system to fulfull their frequency response requirements in all transmission planning scenarios and to track this capability year-over-year. FERC Order 842 states that IBR-based generation must provide frequency response for grid disturbances and newer plants will become a higher proportion than legacy units that do not provide this functionality. The ability of IBR with frequency control enabled to respond to system events must have enough available operating headroom and this must taken into account in the studies.

The objective of this study is to assess the CAISO system frequency response in years 2 and 10 of the system plan and identify performance issues related to frequency response. The study case will be based on the 2027 and 2035 spring off peak cases with the following assumptions on frequency response provided by the IBRs.

<u>*Study Assumptions:*</u>

- The 2027 and 2035 spring off peak cases will be used for this study. Off-peak base cases have a very high solar plant output making them more suitable for studying the effect of IBR impact on frequency response. The details of the base case including the installed and dispatched IBRs, target path flows are provided in earlier sections of this study plan.
- Composite load models will be used in the dynamic study which will more accurately reflect the dependency of load to frequency.
- The assumption is that DERs do not respond to frequency variations. Tripping of DER on significant frequency variations is assumed based on the NERC SPIDER

Guideline recommendations. The settings are such that the DER are not expected to trip in typical frequency events observed in this study.

- In selected scenarios, the online unloaded capacity of non-IBRs in CAISO system will be set at the spinning reserve requirements as much as is possible under that scenario. While it is possible to achieve a particular spinning reserve this can lead to skewed generation patterns that are unrealistic.

Study Scenarios:

Starting with the 2027 and 2035 Spring Off Peak cases, the following scenarios with regards to generator and IBR frequency response will be studied:

- Scenario 1: Frequency response from all new and existing IBRs in CAISO system will have frequency control switched off to establish a baseline. The existing generation pattern will not be modified, nor will any generator statuses be changed from the base case defaults.
- Scenario 2: Frequency response from all new and existing IBRs in CAISO system will have frequency control switched on. As for scenario 1 there is no change in generation output.
- Scenario 3: Frequency response will be enabled for all BESS IBRs assuming 10% headroom. All BESS plants whether in charging or discharging mode are redispatched to this headroom ahead of the contingency.
- Scenario 4: Starting with Scenario 2 it will be assumed that the generator headroom in CAISO areas will be set at minimum spinning reserve.
- Scenario 5: Starting with Scenario 3 it will be assumed that the generator headroom in CAISO areas will be set at minimum spinning reserve.
- Scenario 6 : For 2027 case only with system separation and the loss of a single Paloverde unit.

Study Methodology and Monitored Parameters:

For each of the study scenarios, the trip of two fully dispatched Palo Verde units without a fault, will be simulated for 60 seconds and the following variables will be monitored:

i. System frequency including frequency nadir and settling frequency after primary frequency response

ii. The existing and new IBR output

iii. The total output of all other CAISO generators and how it compares to IBR output

iv. The major path flows

v. Frequency response of the WECC and CAISO (MW/0.1 Hz)

vi. Rate of Change of Frequency (ROCOF)

vii The synchronous inertia of the CAISO and WECC systems

7. Contact Information

This section lists the Subject Matter Experts (SMEs) for each technical study or major stakeholder activity addressed in this document. In addition to the extensive discussion and comment period during and after various CAISO Transmission Plan-related Stakeholder meetings, stakeholders may contact these individuals directly for any further questions or clarifications.

Table 7-6.4-1: SMEs for Technical Studies in 2025-2026 Transmission Planning Process

Item/Issues	SME	Contact
Reliability Assessment in PG&E	Preethi Rondla	prondla@caiso.com
Reliability Assessment in SCE	Frank Chen	fchen@caiso.com
Reliability Assessment in SDG&E	Rene Romo	rromodesantos@caiso.com
Reliability Assessment in VEA	Nikitas Zagoras	nzagoras@caiso.com
Policy-driven Assessment	Meng Zhang Lindsey Thomas	mzhang@caiso.com lthomas@caiso.com
Local Capacity Requirements and Maximum Import Capability Expansion Requests	Catalin Micsa	cmicsa@caiso.com
Economic Planning Study	Yi Zhang	yzhang@caiso.com
Long-term Congestion Revenue Rights	Bryan Fong	bfong@caiso.com

APPENDIX A: System Data

A1 Existing Generation

Table A1-1: Existing generation capacity within the CAISO planning area

		PG&E	SCE	SDG&E	VEA	Total
Existing Generators Max Generation (MW)	**Nuclear**	2,300	0	0	0	**2,300**
	Natural Gas	13,258	13,829	3,129	0	**30,216**
	Hydro	9,316	3,286	0	0	**12,601**
	Solar	5,979	11,800	3,483	364	**21,627**
	Wind	1,845	5,788	702	0	**8,334**
	Biogas	101	178	10	0	**289**
	Biomass	435	4	0	0	**439**
	Geothermal	1,130	552	0	0	**1,682**
	Battery Storage	3,009	7,877	1,976	150	**13,012**
	Hybrid	500	1,796	500	0	**2,796**
	Other	2,304	1,129	785	0	**4,218**
	Total	**40,178**	**46,238**	**10,584**	**514**	**97,514**

For detail resource information, please refer to Master Control Area Generating Capability List in OASIS under ATLAS REFERENCE tab at the following link: http://oasis.caiso.com/mrioasis

A2 Long-Term Planning Procurement Plan Resources

Table A2-1: Planned Generation

PTO Area	Project	Capacity (MW)	Expected In-service Date
None	None	None	None

Table A2-2: Summary of SCE area 2012 LTPP Track 1 & 4 Procurement and Implementation Activities to date

	LTPP EE (MW)	Behind the Meter Solar PV (NQC MW)	Storage 4-hr (MW)	Demand Response (MW)	Conventional resources (MW)	Total Capacity (MW)
SCE's procurement for the Western LA Basin[70]	124.04	37.92	263.64	5	1,382	1,812.60
SCE's procurement for the Moorpark sub-area	6.00	5.66	195[71]	0	0	206.66

The portion of authorized local capacity derived from energy limited preferred resources such as demand response and battery storage will be modeled offline in the initial base cases and will be used as mitigation once reliability concerns are identified.

[70] SCE-selected RFO procurement for the Western LA Basin was approved by the CPUC with PPTAs per Decision 15-11-041, issued on November 24, 2015.

[71] SCE procured 95 MW of the 195 MW energy storage under the ACES program.

A3 Reactive Resources

Table A3-1: Summary of key existing reactive resources modeled in CAISO reliability assessments

Substation	Capacity (MVAr)	Technology
Gates	225	Shunt Capacitors
Los Banos	225	Shunt Capacitors
Gregg	150	Shunt Capacitors
McCall	132	Shunt Capacitors
Mesa (PG&E)	100	Shunt Capacitors
Metcalf	350	Shunt Capacitors
Olinda	200	Shunt Capacitors
Table Mountain	454	Shunt Capacitors
Devers	156 & 605 (dynamic capability)	Static VAr Compensator
Rector	200	Static VAr Compensator
Santiago	3x81	Synchronous Condensers
Mira Loma 230kV	158	Shunt Capacitors
Mira Loma 500kV	300	Shunt Capacitors
San Luis Rey	63	Shunt Capacitors
Bay Boulevard	100	Shunt Capacitors
Miguel	126	Shunt Capacitors
Escondido	126	Shunt Capacitors
Suncrest	126	Shunt Capacitors
Capistrano	150	Shunt Capacitors
Penasquitos	276	Shunt Capacitors
San Luis Rey	2x225	Synchronous Condensers
Talega	2x225	Synchronous Condensers
Miguel	2x225	Synchronous Condensers
San Onofre	225	Synchronous Condensers
Suncrest	300	Static VAr Compensator
Fern Road	264.5	Static VAr Compensator
Orchard	424	Static VAr Compensator

A4 Remedial Action Schemes

Table A4-1: Existing key Remedial Action Schemes in the PG&E area. Additional RAS will be added as needed in the Final Study Plan

PTO	Area	RAS Name
PG&E	Bulk	COI RAS
	Bulk	Colusa RAS
	Bulk	Diablo Canyon RAS
	Bulk	Midway 500/230 kV Transformer Overload RAS
	Bulk	Path 15 IRAS
	Bulk	Path 26 RAS North to South
	Bulk	Path 26 RAS South to North
	Bulk	Table Mt 500/230 kV Bank #1 RAS
	Central Coast / Los Padres	Mesa and Santa Maria Undervoltage RAS
	Central Coast / Los Padres	Divide Undervoltage RAS
	Central Coast / Los Padres	Temblor-San Luis Obispo 115 kV Overload Scheme
	Central Coast / Los Padres	Paso Robles 70 kV Undervoltage RAS
	Central Coast / Los Padres	Coburn Transfer trip
	Central Coast / Los Padres	Carrizo RAS
	Central Valley	Drum (Sierra Pacific) Overload Scheme (Path 24)
	Central Valley	Stanislaus – Manteca 115 kV Line Load Limit Scheme
	Central Valley	Vaca-Suisun 115 kV Lines Thermal Overload Scheme
	Central Valley	West Sacramento 115 kV Overload Scheme
	Central Valley	West Sacramento Double Line Outage Load Shedding RAS Scheme
	Central Valley	Schulte Switching Station-Manteca 115kV Line Thermal Overload Scheme
	Greater Fresno Area	Ashlan RAS
	Greater Fresno Area	Atwater RAS
	Greater Fresno Area	Fresno Reliability Transmission Project RAS
	Greater Fresno Area	Helms RAS
	Greater Fresno Area	Henrietta 230 kV Bank 3 RAS
	Greater Fresno Area	Kerckhoff 2 115 kV gen backing RAS
	Greater Fresno Area	Exchequer - Legrand 115kV RAS
	Greater Fresno Area	Exchequer generation 115 kV scheme

PTO	Area	RAS Name
	Greater Bay Area	Metcalf RAS
	Greater Bay Area	SF RAS
	Greater Bay Area	South of San Mateo RAS
	Greater Bay Area	San Mateo-Bay Meadows 115kV line OL
	Greater Bay Area	Moraga-Oakland J 115kV line OL RAS
	Greater Bay Area	Grant 115kV OL RAS
	Greater Bay Area	Oakland 115 kV C-X Cable OL RAS
	Greater Bay Area	Oakland 115kV D-L Cable OL RAS
	Greater Bay Area	Sobrante-Standard Oil #1 & #2-115kV line
	Greater Bay Area	Gilroy RAS
	Greater Bay Area	Transbay Cable Run Back Scheme
	Kern	Sunrise single line protection scheme
	Humboldt	Humboldt – Trinity 115kV Thermal Overload Scheme
	North Valley	Caribou Generation 230 kV RAS Scheme #1
	North Valley	Caribou Generation 230 kV RAS Scheme #2
	North Valley	Cascade Thermal Overload Scheme
	North Valley	Hatchet Ridge Thermal Overload Scheme
	North Valley	Coleman Thermal Overload Scheme

Table A4-2: Existing key Remedial Action Schemes in SCE area

PTO	Area	RAS Name
SCE	Northern Area	Antelope-RAS
	Northern Area	Big Creek / San Joaquin Valley RAS
	Northern Area	Whirlwind AA-Bank RAS
	Northern Area	Pastoria Energy Facility RAS (PEF RAS)
	Northern Area	Midway-Vincent RAS (SCE MVRAS)
	North of Lugo	Bishop RAS
	North of Lugo	High Desert Power Project RAS (HDPP RAS)
	North of Lugo	Kramer RAS (Retired)
	North of Lugo	Mojave Desert RAS
	North of Lugo	Victor Direct Load Tripping Scheme
	East of Lugo	Ivanpah RAS
	East of Lugo	Lugo - Victorville RAS
	Eastern Area	Devers RAS
	Eastern Area	Colorado River Corridor RAS
	Eastern Area	Inland Empire Area RAS (Retirement pending)
	Eastern Area	Blythe Energy RAS
	Eastern Area	MWD Eagle Mountain Thermal Overload Scheme
	Eastern Area	Mountain view Power Project Remedial Action Scheme
	Metro Area	El Nido LCR RAS (Replaced with El Nido/El Segundo N-2 CRAS Analytic)
	Metro Area	El Segundo RAS (Replaced with El Nido/El Segundo N-2 CRAS Analytic)
	Metro Area	South of Lugo (SOL) N-2 RAS
	Metro Area	Mira Loma Low Voltage Load Shedding (LVLS)

Table A4-3: Existing key Remedial Action Schemes in the SDG&E

PTO	Area	RAS Name
SDG&E	SDG&E	69kV TL 695 at TA
	SDG&E	69kV TL 680C at SM
	SDG&E	69kV TL 600 RAS
	SDG&E	69kV TL 686 RAS
	SDG&E	69kV TL 649 RAS
	SDG&E	Crestwood RAS – Remedial Action Scheme for Kumeyaay Wind Generation (currently disabled and will be removed from service in the future)
	SDG&E	Valley Center RAS
	SDG&E	Avocado RAS
	SDG&E	138kV TL 13810A RAS
	SDG&E	TL23040 IV 500 kV N-1 RAS
	SDG&E	230kV Otay Mesa Gen Drop RAS
	SDG&E	TL 23041 / TL 23042 RAS
	SDG&E	TL 23054 / TL 23055 RAS
	SDG&E	230kV TL 23066 RAS
	SDG&E	230kV TL 23003 / TL 23011 RAS
	SDG&E	230kV TL 23006 RAS
	SDG&E	Miguel BK 80 / BK 81 RAS
	SDG&E	500kV TL 50001 Gen Drop RAS
	SDG&E	500kV TL 50003 Gen Drop RAS
	SDG&E	500kV TL 50004 Gen Drop RAS
	SDG&E	500kV TL 50005 Gen Drop RAS
	SDG&E	South of San Onofre Safety Net

APPENDIX B: Submitted Non-CPUC Jurisdictional Integrated Resource Plan Data

Cumulative New Resources Included in Non-CPUC IRP Plan (in MW)

Resource Type	2026	2027	2028	2029	2030	2035	2040	2045
Natural Gas								
Geothermal		35	35	35	85	95	106	126
Biomass								
Hydrogen Conversion								
Hydrogen Storage								
Wind-NorCal								
Wind-SoCal	330	370	370	370	380	380	390	430
Wind-WY								
Wind-PNW								
Wind-ID								
Wind-NM	125	125	125	125	125	125	125	125
Offshore Wind							10	10
Solar-NorCal		10	170	170	170	170	170	200
Solar-SoCal	224	293	404	404	814	1010	1110	1175
Li-ion Battery (4 hr)	300	370	849	1059	1707	1772	2202	2225
Li-ion Battery (8 hr)								
Pumped Hydro Storage (12 hr)								
Other LDES (8-24 hr)*								
H2 Fuel Cell					35	35	35	75
Shed Demand Response								
Gas Capacity Not Retained	-108	-283	-337	-337	-585	-585	-890	-890
Total	**871**	**920**	**1616**	**1826**	**2731**	**3002**	**3258**	**3476**

* Long-duration energy storage (LDES) technologies include Flow Batteries (8 hr) and Compressed Air Energy Storage (24 hr)

Generic IRP Resources Not Shown in Table:
Baseload Renewable and/or Carbon-free (Baseload Resource Tranche) is a generic resource studied in RPU's 2023 IRP for planning purposes. The resource supplies 50MW in 2034, an additional 60MW in 2038, and an additional 20MW in 2043.

Gas Capacity not retained

Year Capacity not Retained	RESOURCE_ID	GEN_UNIT_NAME	NET_DEPENDABLE_CAPACITY (MW)	NAMEPLATE_CAPACITY (MW)	UNIT_TYPE	ENERGY_SOURCE	Substation	Voltage	PSLF Bus No.	Unit ID
2026	INTMNT_3_PASADENA	Intermountain Coal	108	108	Steam Turbine	Coal	Sylmar	220 kV		
2028	INTMNT_3_CC_3_PASADENA	Intermountain Repwr	27	27	2 + 1 Combined Cycle	Natgas	Sylmar	220 kV		
2028	INTMNT_3_CC_4_PASADENA	Intermountain Repwr	27	27	2 + 1 Combined Cycle	Natgas	Sylmar	221 kV		
2037	PASA_SLYMAR_I_UC_MAGNOL / MAGNLA_6_PASADENA	Magnolia	14	15	1 + 1 Combined Cycle	Natgas & Landfill Gas	Sylmar	220 kV		
2027	INTMNT_3_CC_3_RIVERSIDE	Intermountain Generating Station Unit 3[c]	37	37	DYN_TG	GAS				
2027	INTMNT_3_CC_4_RIVERSIDE	Intermountain Generating Station Unit 4[c]	37	37	DYN_TG	GAS				
2031	RVSIDE_6_SPRING	Springs Generation Project[f]	36	36	GEN	GAS				
2040	RVSIDE_6_RERCU1	Riverside Energy Resource Center Unit 1[i]	48.5	48.5	GEN	GAS				
2040	RVSIDE_6_RERCU2	Riverside Energy Resource Center Unit 2[i]	48.5	48.5	GEN	GAS				
2040	RVSIDE_2_RERCU3	Riverside Energy Resource Center Unit 3[i]	48.5	48.5	GEN	GAS				
2040	RVSIDE_2_RERCU4	Riverside Energy Resource Center Unit 4[i]	48.5	48.5	GEN	GAS				
2040	CORONS_6_CLRWTR	Clearwater[i]	28.5	28.5	GEN	GAS				
2031	WALNUT_6_HILLGEN	Puente Hills		10		Biomass	Walnut 220 kV	220 kV	24063	
2036	VERNON_6_MALBRG	Malburg	67	139		Natural Gas	LAGUNA BELL 230	230 kV	24076	

Notes:

Intermountain Generating Station U3 and U4 single unit operations PMAX = 37MW, two unit operations PMAX = 64MW. IPP U3 and U4 currently in NRI.

c) Riverside exits Intermountain Power Project in June 2027. A total of 64MW from IPP Unit 3 and 4 exits Riverside's Portfolio. Riverside's IPP transmission entitlement ends June 2027.

f) Riverside's Springs Generation Facility totaling 36MW expected to retire after 2030.

i) Riverside's 194MW RERC Facility and 28.5MW Clearwater Facility are expected to retire after 2039.

Anaheim Public Utilities

Resource Type	2026**	2027**	2028**	2029**	2030	2035	2040	2045
Natural Gas	410.82	410.82	299.78	299.82	299.82	299.82	193.54	
Geothermal	9.90	9.90	9.90	9.90	9.90	-	-	
Biomass	47.40	47.40	47.40	47.40	47.40	47.40	27.80	
Hydrogen Conversion								
Wind-NorCal								
Wind-SoCal	5.80	11.70	11.70	11.70	11.70	11.70	-	
Wind-WY								
Wind-PNW								
Wind-ID								
Wind-NM								
Offshore Wind								
Solar-NorCal								
Solar-SoCal	2.00	2.00	51.73	102.00	102.00	102.00	102.00	
Li-ion Battery (4 hr)			300.00	300.00	300.00	300.00	300.00	
Li-ion Battery (8 hr)								
Pumped Hydro Storage (12 hr)								
Other LDES (8-24 hr)*								
Shed Demand Response								
Gas Capacity Not Retained								
Large Hydro	30.30	30.30	30.30	30.30	30.30	30.30	30.30	
Small Hydro	12.50	12.50	12.50	12.50	12.50	12.50	6.28	
Total	**518.72**	**524.62**	**763.31**	**813.62**	**813.62**	**803.72**	**659.92**	-

* Long-duration energy storage (LDES) technologies include Flow Batteries (8 hr) and Compressed Air Energy Storage (24 hr)

** If there is planned resources in the early years before 2030, please also include a separate Resources by Substation tab for each year

All values are capacity information per resource type

Anaheim does not have any Gas Capacity not Retained. 111MW of Natural Gas Capacity expires in 2027.

CAISO Study Area	Substation	PSLF Bus Number	Voltage	Resource Type	ISO Queue if Available	POU Note	2035									2040								
							Total Portfolio			In-Development			Generic			Total Portfolio			In-Development			Generic		
							FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total
SCE Eastern	Devers		230	Wind SoCal		Karen Wind	11.7		11.7															
SCE Eastern	Colorado River		230	Solar SoCal	1761	Grace			100															
SCE Metro	Mira Loma		230	Li-ion Battery (4 hr)	1768	Road House			300															

Pasadena Water and Power

Resource Type	2025**	2026**	2027**	2028**	2029**	2030	2035	2040	2045	
Natural Gas										
Geothermal			35			10		11	20	
H2 Fuel Cells						35			40	(Added this row to CAISO's template)
Biomass										
Hydrogen Conversion										
Wind-NorCal										
Wind-SoCal	30								30	
Wind-WY										
Wind-PNW										
Wind-ID										
Wind-NM										
Offshore Wind										
Solar-NorCal										
Solar-SoCal	185		39			400	60		-20	
Li-ion Battery (4 hr)	85		20		10	570	15		13	
Li-ion Battery (8 hr)										
Pumped Hydro Storage (12 hr)										
Other LDES (8-24 hr)*										
Shed Demand Response										
Gas Capacity Not Retained						-212				
Total of New Resou	**300**	**0**	**94**	**0**	**10**	**803**	**75**	**11**	**83**	

* Long-duration energy storage (LDES) technologies include Flow Batteries (8 hr) and Compressed Air Energy Storage (24 hr)
** If there are planned resources in the early years before 2030, please also include a separate Resources by Substation tab for each year

[All numbers are in incremental MW; negative numbers denote retirements]

Ref.: 2023 IRP, Figs. 118 and 207 for Scenario 2

Year Capacity not Retained	RESOURCE_ID	GEN_UNIT_NAME	NET_DEPENDABLE_CAPACITY (MW)	NAMEPLATE_CAPACITY (MW)	UNIT_TYPE	ENERGY_SOURCE	Substation	Voltage	PSLF Bus No.	Unit ID
2037	PASA_SLYMAR_I	Magnolia	14	15	1 + 1 Coml	Natgas & Landfi	Sylmar	220 kV		
2026	INTMNT_3_PASA	Intermountain Co	108	108	Steam Tur	Coal	Sylmar	220 kV		
2028	INTMNT_3_CC_3	Intermountain Re	27	27	2 + 1 Coml	Natgas	Sylmar	220 kV		
2028	INTMNT_3_CC_4	Intermountain Re	27	27	2 + 1 Coml	Natgas	Sylmar	221 kV		

Notes:
This sheet includes coal capacity not retained.
In this report, "not retained" means divested, expired or retired.

CAISO Study Area	Substation	PSLF Bus Number	Voltage	Resource Type	ISO Queue if Available	POU Note	2035									2040								
							Total Portfolio			**In-Development**			**Generic**			**Total Portfolio**			**In-Development**			**Generic**		
							FCDS	**EODS**	**Total**	**FCDS**	**EODS**	**Total**	**FCDS**	**EODS**	**Total**	**FCDS**	**EODS**	**Total**	**FCDS**	**EODS**	**Total**	**FCDS**	**EODS**	**Total**
PG&E Kern	Arco		70	Wind		CalWind		20	20		20	20												
SCE Metro	Goodrich		230	BESS		Glenarm BESS	25		25	25		25												
SCE NOL	(multiple)		115	Geothermal		Coso	20		20				20		20									
PG&E NGBA	(multiple)		115	Geothermal		Geysers	25		25				25		25									
SCE Eastern	Red Bluff		230	Solar	1764	Sapphire		39	39		39	39												
SCE Eastern	Red Bluff		230	BESS	1764	Sapphire	20		20	20		20												
SCE EOP	Innovation		230	Solar	1649	Bonanza		105	105		105	105												
SCE EOP	Innovation		230	BESS	1649	Bonanza	55		55	55		55												
SCE Eastern	Colorado River		230	Solar	1761	Grace		50	50		50	50												

City of Riverside

Resource Type	2026**	2027**	2028**	2029**	2030	2035	2040	2045
Natural Gas								
Geothermal					50[e]			
Biomass								
Hydrogen Conversion								
Wind-NorCal								
Wind-SoCal								
Wind-WY								
Wind-PNW								
Wind-ID								
Wind-NM	125[a]							
Offshore Wind								
Solar-NorCal								
Solar-SoCal							75[g]	75[g]
Li-ion Battery (4 hr)	80[b]	50[j]	18[d]		18[d]		200[h]	
Li-ion Battery (8 hr)								
Pumped Hydro Storage (12 hr)								
Other LDES (8-24 hr)*								
Shed Demand Response								
Gas Capacity Not Retained		64[c]			36[f]		222.5[i]	
Total	**205**	**-14**	**18**		**32**		**52.5**	**75**

* Long-duration energy storage (LDES) technologies include Flow Batteries (8 hr) and Compressed Air Energy Storage (24 hr)
** If there is planned resources in the early years before 2030, please also include a separate Resources by Substation tab for each year

Notes:
a) Riverside's SunZia Wind Project Share
b) Riverside's contracted Shirk Energy Storage Facility
c) Riverside exits Intermountain Power Project in June 2027. A total of 64MW from IPP Unit 3 and 4 exits Riverside's Portfolio. Riverside's IPP transmission entitlement ends June 2027.
d) Riverside's 2023 IRP studied staging in Li-ion Battery (4hr) to replace the 36MW Springs Generation Facility, specifically 18MW in 2028 and another 18MW in 2030.
e) New resource options studied in RPU's 2023 IRP [Baseload Geothermal or Solar PV + Li-ion Battery (4hr)]. Specific projects have not been identified.
f) Riverside's Springs Generation Facility totaling 36MW expected to retire after 2030.
g) Riverside's 2023 IRP Baseline Portfolio included 75 MW from generic solar PV resources in 2037 and 2041. These solar resources have not been identified.
h) Riverside's 2023 IRP studied replacing the Riverside Energy Resource Center (RERC) with 200MW of Li-ion Battery (4hr).
i) Riverside's 194MW RERC Facility and 28.5MW Clearwater Facility are expected to retire after 2039.
j) Riverside's anticipated contract with the Baldy Mesa C Facility. This contract is pending Riverside's Public Utilities Board and City Council approvals.

Generic IRP Resources Not Shown in Table:
Baseload Renewable and/or Carbon-free (Baseload Resource Tranche) is a generic resource studied in RPU's 2023 IRP for planning purposes. The resource supplies 50MW in 2034, an additional 60MW in 2038, and an additional 20MW in 2043.

IRP Reference:
For additional details about Riverside's proposed resource procurment and Baseline IRP Portfolio, please refer to Chapter 11 of Riverside's 2023 IRP. Table 11.2.1 shows Riverside's proposed new resources for 2030-2045. Note that these resources are all generic -- Riverside has not identified specific, proposed projects queued for development.

Year Capacity not Retained	RESOURCE_ID	GEN_UNIT_NAME	NET_DEPENDABLE_CAPACITY (MW)	NAMEPLATE_CAPACITY (MW)	UNIT_TYPE	ENERGY_SOURCE	Substation	Voltage	PSLF Bus No.	Unit ID
2027	INTMNT_3_CC_3_R	Intermountain (	37	37	DYN_TG	GAS				
2027	INTMNT_3_CC_4_R	Intermountain (	37	37	DYN_TG	GAS				
2031	RVSIDE_6_SPRING	Springs Generat	36	36	GEN	GAS				
2040	RVSIDE_6_RERCU1	Riverside Energ	48.5	48.5	GEN	GAS				
2040	RVSIDE_6_RERCU2	Riverside Energ	48.5	48.5	GEN	GAS				
2040	RVSIDE_2_RERCU3	Riverside Energ	48.5	48.5	GEN	GAS				
2040	RVSIDE_2_RERCU4	Riverside Energ	48.5	48.5	GEN	GAS				
2040	CORONS_6_CLRWTI	Clearwater[i]	28.5	28.5	GEN	GAS				

Notes:
Intermountain Generating Station U3 and U4 single unit operations PMAX = 37MW, two unit operations PMAX = 64MW. IPP U3 and U4 currently in NRI.
c) Riverside exits Intermountain Power Project in June 2027. A total of 64MW from IPP Unit 3 and 4 exits Riverside's Portfolio. Riverside's IPP transmission entitlement ends June 2027.
f) Riverside's Springs Generation Facility totaling 36MW expected to retire after 2030.
i) Riverside's 194MW RERC Facility and 28.5MW Clearwater Facility are expected to retire after 2039.

CAISO Study Area	Substation	PSLF Bus Number	Voltage	Resource Type	ISO Queue if Available	POU Note	2035									2040								
							Total Portfolio			In-Development			Generic			Total Portfolio			In-Development			Generic		
							FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total
SCE Eastern	Palo Verde			Wind-NM[a]	0148CONV 0149CONV		125		125	125		125												
SCE Northern	Woodrat			Li-ion Battery (4 hr)[b]	WDT1650		80		80	80		80												
SCE NOL	Roadway		115	Li-ion Battery (4 hr)[j]	1413 and/or 1519		50		50	50		50												
SCE Eastern	Unknown	Unknown	Unknown	Li-ion Battery (4 hr)[d,h]	n/a		36		36				36		36	200		200				200		200
Unknown	Unknown	Unknown	Unknown	Geothermal (Baseload)[e]	n/a		50		50				50		50									
Unknown	Unknown	Unknown	Unknown	Solar[e,g]	n/a		120		120				120		120	75		75				75		75
Unknown	Unknown	Unknown	Unknown	Li-ion Battery (4 hr)	n/a		50		50				50		50									
Unknown	Unknown	Unknown	Unknown	Baseload Renewable and/or Carbon-Fre	n/a		50		50				50		50	60		60				60		60

Notes:
a) Riverside's SunZia Wind Project Share
b) Riverside's contracted Shirk Energy Storage Facility
j) Riverside's anticipated contract with the Baldy Mesa C Facility. This contract is pending Riverside's Public Utilities Board and City Council approvals.
d) RPU's 2023 IRP studied staging in Li-ion Battery (4hr) to replace the 36MW Springs Generation Facility, specifically 18MW in 2028 and another 18MW in 2030.
e) New resource options studied in RPU's 2023 IRP [Baseload Geothermal or Solar PV + Li-ion Battery (4hr)]. Specific projects have not been identified.
Baseload Renewable and/or Carbon-free (Baseload Resource Tranche) is a generic resource studied in RPU's 2023 IRP for planning purposes. The resource supplies 50MW in 2034, an additional 60MW in 2038, and an additional 20MW in 2043.
g) RPU's 2023 IRP Baseline Portfolio included 75 MW from generic solar PV resources in 2037 and 2041. These solar resources have not been identified.
h) Riverside's 2023 IRP studied replacing the Riverside Energy Resource Center (RERC) with 200MW of Li-ion Battery (4hr).

City of Vernon

Resource Type	2026**	2027**	2028**	2029**	2030	2035	2040	2045
Natural Gas	150.5	150.5	150.5	150.5	78.5	78.5	11.5	11.5
Geothermal	0	0	0	0	0	0	0	0
Biomass	10	10	10	10	10	0	0	0
Hydrogen Conve	0	0	0	0	0	0	0	0
Wind-NorCal	0	0	0	0	0	0	0	0
Wind-SoCal	0	40	40	40	50	50	60	70
Wind-WY	0	0	0	0	0	0	0	0
Wind-PNW	0	0	0	0	0	0	0	0
Wind-ID	0	0	0	0	0	0	0	0
Wind-NM	0	0	0	0	0	0	0	0
Offshore Wind	0	0	0	0	0	0	10	10
Solar-NorCal	0	10	20	20	20	20	20	50
Solar-SoCal	154	164	164	164	174	314	339	349
Li-ion Battery (4	49.7	49.7	49.7	49.7	109.7	159.7	389.7	399.7
Li-ion Battery (8 hr)								
Pumped Hydro Storage (12 hr)								
Other LDES (8-24 hr)*								
Shed Demand Response								
Gas Capacity Not Retained								
Total	**364.2**	**424.2**	**434.2**	**434.2**	**442.2**	**622.2**	**830.2**	**890.2**

* Long-duration energy storage (LDES) technologies include Flow Batteries (8 hr) and Compressed Air Energy Storage (24 hr)
** If there is planned resources in the early years before 2030, please also include a separate Resources by Substation tab for each year

Year Capacity not Retained	RESOURCE_ID	GEN_UNIT_NAME	NET_DEPENDABLE_CAPACITY (MW)	NAMEPLATE_CAPACITY (MW)	UNIT_TYPE	ENERGY_SOURCE	Substation	Voltage	PSLF Bus No.	Unit ID
2036	VERNON_6_MA	Malburg	67	139		Natural Ga	LAGUNA B	230 kV	24076	
2031	WALNUT_6_HIL	Puente Hills		10		Biomass	Walnut 22	220 kV	24063	

CAISO Study Area	Substation	PSLF Bus Number	Voltage	Resource Type	ISO Queue if Available	POU Note	2035									2040								
							Total Portfolio			In-Development			Generic			Total Portfolio			In-Development			Generic		
							FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total
SCE Eastern	Red Bluff	24375	230	Solar	1764		39		39	39		39				39		39	39		39			
SCE Eastern	Red Bluff	24375	230	BESS	1764		19.67		19.67	19.67		19.67				19.67		19.67	19.67		19.67			
SCE Metro	Laguna Bell	24076	230	Gas					67							0		0						
SCE Metro	Laguna Bell	24076	230	Gas					11.5							11.5		11.5						
SCE Northern	Antelope	29731	230	Solar					25							0		0						
SCE Northern	Whirlwind	29408	230	Solar					30							0		0						
SCE NOL	Kramer	24701	230	Solar					60							60		60						
SCE NOL	Kramer	24701	230	BESS					30							30		30						
				Wind			50		50				50		50	60		60				60		70
				Solar-NorCal			20		20				20		20	20		20				20		20
				Solar-SoCal			160		160				160		160	240		240				240		240
				BESS			110		110				110		110	340		340				340		340
				OSW												10		10				10		10

NCPA

Resource Type	2026**	2027**	2028**	2029**	2030	2035	2040	2045
Natural Gas		19.00						
Geothermal								
Biomass								
Hydrogen Conversion								
Hydrogen Storage		60.00						
Wind-NorCal								
Wind-SoCal								
Wind-WY								
Wind-PNW								
Wind-ID								
Wind-NM								
Offshore Wind								
Solar-NorCal			150.00					
Solar-SoCal								
Li-ion Battery (4 hr)			150.00	200.00				
Li-ion Battery (8 hr)								
Pumped Hydro Storage (12 hr)								
Other LDES (8-24 hr)*								
Shed Demand Response								
Gas Capacity Not Retained								
Total								

* Long-duration energy storage (LDES) technologies include Flow Batteries (8 hr) and Compressed Air Energy Storage (24 hr)
** If there is planned resources in the early years before 2030, please also include a separate Resources by Substation tab for each year

CAISO Study Area	Substation	PSLF Bus Number	Voltage	Resource Type	ISO Queue if Available	POU Note	2035									2040								
							Total Portfolio			In-Development			Generic			Total Portfolio			In-Development			Generic		
							FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total
PG&E NGBA	Gold Hill-Eight Mile Road 230 kV line		230	Hydrogen Storage	N/A		60	0	60	0	0	0	60	0	60									
PG&E NGBA	Gold Hill-Eight Mile Road 230 kV line		230	Natural Gas	N/A		19	0	19	19	0	19	0	0	0									
PG&E Fresno	Los Banos - Midway #2 500 kV line		500	Solar-NorCal	54689	Cluster 15 project number	150	0	150	0	0	0	150	0	150									
PG&E Fresno	Los Banos - Midway #2 500 kV line		500	Li-ion Battery (4 hr)	54689		150	0	159	0	0	0	150	0	150									
PG&E GBA	Bellota		230	Li-ion Battery (4 hr)	N/A		200	0	200	0	0	0	200	0	200									

SVP

Resource Type	2025**	2026**	2027**	2028**	2029**	2030	2035	2040	2045
Natural Gas									
Geothermal									
Biomass									
Hydrogen Conversion									
Hydrogen Storage									
Wind-NorCal			49.00						
Wind-SoCal		300.00							
Wind-WY									
Wind-PNW									
Wind-ID									
Wind-NM									
Offshore Wind									
Solar-NorCal									
Solar-SoCal									
Li-ion Battery (4 hr)		50.00							
Li-ion Battery (8 hr)									
Pumped Hydro Storage (12 hr)									
Other LDES (8-24 hr)*									
Shed Demand Response									
Gas Capacity Not Retained									
Total									

* Long-duration energy storage (LDES) technologies include Flow Batteries (8 hr) and Compressed Air Energy Storage (24 hr)

** If there is planned resources in the early years before 2030, please also include a separate Resources by Substation tab for each year

CAISO Study Area	Substation	PSLF Bus Number	Voltage	Resource Type	ISO Queue if Available	POU Note	2035									2040								
							Total Portfolio			In-Development			Generic			Total Portfolio			In-Development			Generic		
							FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total
PG&E GBA	KEN-OKJ 60 kV		60	Li-ion Battery (4 hr)	1918		50	0	50	50	0	50	0	0	0									
SDGE	East County		230	Wind	1660		300	0	300	300	0	300	0	0	0									
PG&E GBA	Zond		60	Wind	N/A		19	0	19	19	0	19	0	0	0									
PG&E GBA	Altamont		60	Wind	N/A		13	0	13	13	0	13	0	0	0									
PG&E GBA	Altamont		60	Wind	N/A		17	0	17	17	0	17	0	0	0									

Colton Electric Utility

Resource Type	2026**	2027**	2028**	2029**	2030	2035	2040	2045
Natural Gas								
Geothermal								
Biomass								
Hydrogen Conversion								
Wind-NorCal								
Wind-SoCal								
Wind-WY								
Wind-PNW								
Wind-ID								
Wind-NM								
Offshore Wind								
Solar-NorCal								
Solar-SoCal		Grace Solar Orchard	Aypa Solar					
Li-ion Battery (4 hr)			Aypa BESS					
Li-ion Battery (8 hr)								
Pumped Hydro Storage (12 hr)								
Other LDES (8-24 hr)*								
Shed Demand Response								
Gas Capacity Not Retained								
Total								

* Long-duration energy storage (LDES) technologies include Flow Batteries (8 hr) and Compressed Air Energy Storage (24 hr)
** If there is planned resources in the early years before 2030, please also include a separate Resources by Substation tab for each year

CAISO Study Area	Substation	PSLF Bus Number	Voltage	Resource Type	ISO Queue if Available	POU Note	2035									2040								
							Total Portfolio			In-Development			Generic			Total Portfolio			In-Development			Generic		
							FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total
SCE Eastern	Colorado River		230	Solar		Grace Solar			20			20												
PG&E Kern	Arco		230	Solar		Aypa Solar			11			11												
PG&E Kern	Arco		230	BESS		Aypa BESS			11			11												

VEA

Resource Type	2026**	2027**	2028**	2029**	2030	2035	2040	2045	
Natural Gas									
Geothermal									
Biomass									
Hydrogen Conversion									
Wind-NorCal									
Wind-SoCal									
Wind-WY									
Wind-PNW									
Wind-ID									
Wind-NM									
Offshore Wind									
Solar-NorCal									
Solar-SoCal (Vista Sola	15	15	15	15	15	15	15	15	aka "Community Solar"
Li-ion Battery (4 hr) (V	35	35	35	35	35	35	35	35	
Li-ion Battery (8 hr)									
Pumped Hydro Storage (12 hr)									
Other LDES (8-24 hr)*									
Shed Demand Response									
Gas Capacity Not Retained									
Solar/Storage PPA (Tc	90	90	90	90	90	90	90	90	
Solar/Storage PPA (Pinal Solar)		30	30	30	30	30	30	30	
Hydro (Various PPAs)	32	32	32	32	32	32	32	32	
Total	**172**	**202**	**202**	**202**	**202**	**202**	**202**	**202**	

* Long-duration energy storage (LDES) technologies include Flow Batteries (8 hr) and Compressed Air Energy Storage (24 hr)
** If there is planned resources in the early years before 2030, please also include a separate Resources by Substation tab for each year

CAISO Study Area	Substation	PSLF Bus Number	Voltage	Resource Type	ISO Queue if Available	POU Note	2035									2040								
							Total Portfolio			In-Development			Generic			Total Portfolio			In-Development			Generic		
							FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total	FCDS	EODS	Total
SCE EOP	Vista	189013	138	Li-ion Battery (4 hr)		COD: 2026		35	35		35	35												
SCE EOP	Mead S	19012	230	Solar/BESS PPA	Import Capacity	Existing		90	90															
Not in CAISO	Pinal West	15088	500	Solar/BESS PPA		COD: 2027		30	30		30	30												
SCE EOP	Mead S	19012	230	Hydroelectric	Import Capacity	Existing		32	32															
SCE EOP	Vista	189013	138	Solar		Existing		15	15															