California ISO

2021-2022 Transmission Planning Process Unified Planning Assumptions And Study Plan

March 31, 2021

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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 2021-2022 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 2020 IEPR adopted by the CEC on January 25, 2021[1].

[1] https://ww2.energy.ca.gov/2019_energypolicy/documents/#demand

1.1 Overview of 2021-2022 Stakeholder Process Activities and Communications

Section 2 of this document 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 2021-2022 transmission planning process is provided in Table 1.1-1. Should this schedule change or other aspects of the 2021-2022 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:

http://www.caiso.com/informed/Pages/Notifications/MarketNotices/MarketNoticesSubscriptionForm.aspx

Table 1.1-1: Schedule for the 2021-2022 planning cycle

Phase	No	Due Date	2021-2022 Activity
Phase 1	1	January 6, 2021	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	January 6, 2021	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	February 6, 2021	PTO's, neighboring balancing authorities and regional/sub-regional planning groups provide CAISO the information requested No.1 above.
	4	February 6, 2021	Stakeholders provide CAISO the information requested No.2 above.
	5	February 18, 2021	The CAISO develops the draft Study Plan and posts it on its website
	6	February 25, 2021	The CAISO hosts public stakeholder meeting #1 to discuss the contents in the Study Plan with stakeholders
	7	February 25- March 11, 2021	Comment period for stakeholders to submit comments on the public stakeholder meeting #1 material and for interested parties to submit Economic Planning Study Requests to the CAISO
	8	March 31, 2021	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	9	August 13, 2021	The CAISO posts preliminary reliability study results and mitigation solutions
	10	August 13, 2021	Request Window opens
	11	August 27, 2021	The CAISO will post base scenario base cases for each planning area used in the reliability assessment
	12	September 15, 2021	PTO's submit reliability projects to the CAISO
	13	September 27-28, 2021	The CAISO hosts public stakeholder meeting #2 to discuss the reliability study results, PTO's reliability projects, and the Conceptual Statewide Plan with stakeholders
	14	September 27 – October 12, 2021	Comment period for stakeholders to submit comments on the public stakeholder meeting #2 material[2]

[2] The ISO 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.

Phase	No	Due Date	2021-2022 Activity
	15	October 15, 2021	Request Window closes
	16	October 29, 2021	The CAISO post final reliability study results
	17	November 15, 2021	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.
	18	November 18, 2021	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.
	19	November 18 – December 6, 2021	Comment period for stakeholders to submit comments on the public stakeholder meeting #3 material
	20	December 15 – 16, 2021	The CAISO Board of Governors meeting provides opportunity for stakeholder comments directly to Board of Governors.
	21	January 31, 2022	The CAISO posts the draft Transmission Plan on the public website
	22	February 2022	The CAISO hosts public stakeholder meeting #4 to discuss the transmission project approval recommendations, identified transmission elements, and the content of the Transmission Plan
	23	Approximately two weeks following the public stakeholder meeting #4	Comment period for stakeholders to submit comments on the public stakeholder meeting #4 material
	24	March 2022	The CAISO finalizes the Transmission Plan and presents it to the CAISO Board of Governors for approval
	25	End of March, 2022	The CAISO posts the Final Board-approved Transmission Plan on its site
Phase 3	26[3]	April 1, 2022	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 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 Data Request Letter:

- The CPUC Public Advocates Office (PAO) suggested including grid integration study of off-shore wind generation. Off-shore wind generation is a part of the CPUC sensitivity portfolio for policy-driven study.
- IID provided the latest outage and RAS files.
- Desert Link LLC/ LS Power provided information about no changes to its equipment and had no updates for both planning and contingency data. In addition, it does not have any equipment with a long lead time - extending a year or more.
- Hetch Hetchy Water & Power provided topology change-files for years 2021-23 and 2024--2031.
- BPA did not provide any additional planning data for the 2021-2022 TPP process.
- Merced ID did not have any further data updates and relied on load, demand and resource planning data embedded in TID's submittals.
- City of Pasadena stated that they did not have any further data updates for the 2021-2022 TPP process.
- SMUD provided 1 in 10 load forecast data for 2021-2031.
- TBC provided list of contingency files for the 2021-2022 TPP process.
- TANC did not provide any additional planning related modeling data for the 2021-2022 TPP process. However, TANC provided comments related to automatic system operation, contingencies, spare equipment and other planning information requested in the ISO letter.
- SVP provided load & topology change files for multiple years for the 2021-2022 TPP process.

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 in writing to regionaltransmission@caiso.com within two weeks after the stakeholder meetings. The CAISO will post these comments on the CAISO Website. 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.

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 2021-2022 transmission planning cycle is the "Transmission Planning" section located at http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx 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://portal.caiso.com/tp/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 http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx 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 3.1-3.15. 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 2021-2022 transmission plan will span a 10-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 2021-2030 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:[4]

TPL-001-5[5]: Transmission System Planning Performance Requirements[6]; and

NUC-001-3 Nuclear Plant Interface Coordination.[7]

[4] http://www.nerc.com/page.php?cid=2%7C20

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.

2.1.2 WECC Regional Criteria

The WECC System Performance TPL-001-WECC-CRT-3.2[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.

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.

2.2 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 Standard. Within the Standard, the Requirement R2.6 allows for use of past studies to support the planning assessment. Similar to the last TPP 20-21 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.

[7] https://www.wecc.org/Reliability/TPL-001-WECC-CRT-3.2.pdf
[8] http://www.caiso.com/Documents/ISOPlanningStandards-September62018.pdf

2.3 Study Horizon and Years

The studies that comply with TPL-001-5 will be conducted for both the near-term[9] (2022-2026) and longer-term[10] (2027-2031) 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 2023, 2026 and 2031. 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[11] in the areas as appropriate.

2.4 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 2.4-1 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 16 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 – 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

9 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.
10 System peak load conditions for one of the years and the rationale for why that year was selected.
11 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.

- Metro area.

- San Diego Gas & Electric (SDG&E) main transmission
- San Diego Gas & Electric (SDG&E) sub-transmission
- Valley Electric Association (VEA) area[12]
- CAISO overall bulk system

Figure 2.4-1: Approximated geographical locations of the study areas

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

2.5 Transmission Assumptions

2.5.1 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 2020-2021 or earlier CAISO transmission plans. Currently, the CAISO anticipates the 2020-2021 transmission plan will be presented to the CAISO board of governors for approval in March 2021. Projects put on hold will not be modeled in the starting base case.

2.5.2 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.

2.5.3 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.

2.5.4 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

2.6 Load Forecast Assumptions

2.6.1 Energy and Demand Forecast

The assessment will utilize the 2020 California Energy Demand Forecast Update 2020-2030 adopted by the California Energy Commission (CEC) on January 25, 2021[13] using the corresponding LSE and BA Table Mid Baseline spreadsheet with applicable AAEE. The 2020 CED updated Forecast also includes 8760-hourly demand forecasts for the three major Investor Owned Utility (IOU) TAC areas[14].

During 2019, the CEC, CPUC and CAISO engaged in collaborative discussion on how to consistently account for reduced energy demand from energy efficiency in the planning and procurement processes. To that end, the 2020 IEPR final report, adopted on January 25, 2021 based on the IEPR record and in consultation with the CPUC and the CAISO, recommends using the Mid Additional Achievable Energy Efficiency (AAEE) scenario 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 and AAEE at specific locations and estimating their daily load-shape impacts, using the Low AAEE scenario is more prudent at this time.

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

https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=20-IEPR-03

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 with low AAEE savings 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 with mid AAEE savings load forecast will be used for system studies
- The 1-in-2 weather year, mid demand baseline with mid AAEE savings load forecast will be used for production cost study.

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 (TPP).

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13 https://ww2.energy.ca.gov/2019_energypolicy/documents/#demand

14 https://www.energy.ca.gov/2018_energypolicy/documents/cedu_2018-2030/2018_demandforecast.php

To ensure the VEA load forecast has incorporated relevant information, VEA provides 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 is typically 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 reviews 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.

2.6.2 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.

2.6.2.1 Pacific Gas and Electric Service Area

The method used to develop the PG&E base case loads is an integrative process that extracts, adjusts and modifies the information from the transmission and distribution systems and municipal utility forecasts. The melding process consists of two parts. Part 1 deals with the PG&E load. Part 2 deals with the municipal utility loads.

PG&E Loads in Base Case

The method used to determine the PG&E loads is similar to the one used in the previous year's studies. The method consists of determining the division loads for the required 1-in-5 system or 1-in-10 area base cases as well as the allocation of the division load to the transmission buses.

<u>Determination of Division Loads</u>

The annual division load is determined by summing the previous year division load and the current division load growth. The initial year for the base case development method is based heavily on the most recent recorded data. The division load growth in the system base case is determined in two steps. First, the total PG&E load growth for the year is determined. Then this total PG&E load growth is allocated to the division, based on the relative magnitude of the load growths projected for the divisions by PG&E's distribution planners. For the 1-in-10 area base case, the division load growth determined for the system base case is adjusted to the 1-in-10 temperature using the load temperature relation determined from the most recent load and temperature data of the division.

Allocation of Division Load to Transmission Bus Level

Since the base case loads are modeled at the various transmission buses, the division loads developed need to be allocated to those buses. The allocation process is different depending on the load types. PG&E classifies its loads into four types: conforming, non-conforming, self-generation and generation-plant loads. The conforming, non-conforming and self-generation loads are included in the division load. Because of their variability, the generation-plant loads are not included in the division load. Since the non-conforming and self-generation loads are assumed to not vary with temperature, their magnitude would be the same in the 1-in-2 system, 1-in-5 system or the 1-in-10 area base cases of the same year. The remaining load (the total division load developed above, less the quantity of non-conforming and self-generation load) is the conforming load, which is then allocated to the transmission buses based on the relative magnitude of the distribution level forecast.

Muni Loads in Base Case

Municipalities provide PG&E their load forecast information. If no information is provided, PG&E supplements such forecast. For example, if a municipal utility provided only the 1-in-5 loads, PG&E would determine the 1-in-2 and 1-in-10 loads by adjusting the 1-in-5 loads for temperature in the same way that PG&E would for its load in that area.

For the 1-in-5 system base cases, the 1-in-5 loads are used. For the 1-in-10 area base cases, the 1-in-10 loads are used if the municipal loads are in the area of the area base case, otherwise, the 1-in-2 loads would be used.

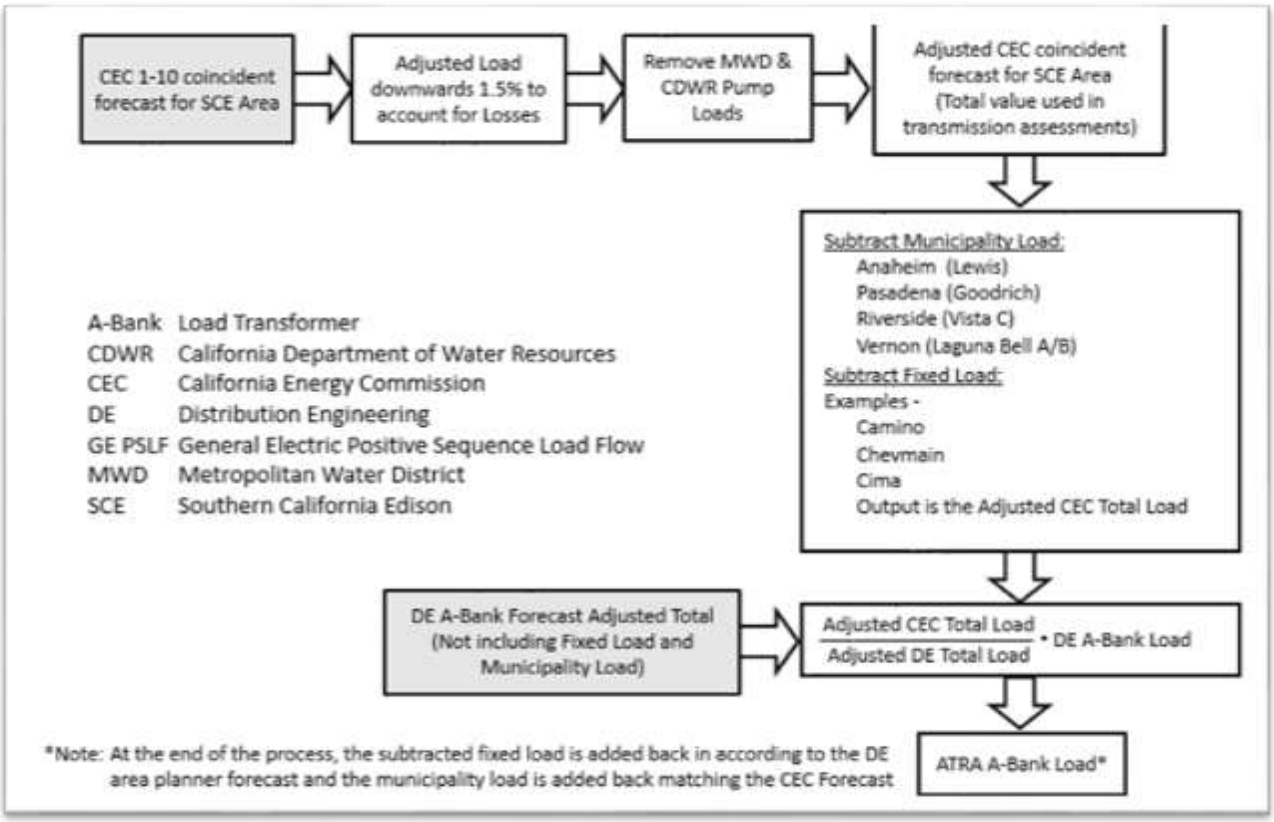
Behind-the-meter PV (BTM-PV)

BTM-PV will be modeled as a component of the load model. Using the DG field on the PSLF load model the total nameplate capacity of the DG will be represented under PDGmax field, and the actual output will be based on the scenario. The total nameplate capacity is specified by the CEC, the allocation and location for projected DG is derived from the latest Distribution Resource Plan (DRP) filed with the CPUC as provided by Distribution Planning.

2.6.2.2 Southern California Edison Service Area

The following figure identifies the steps in developing SCE's A-Bank load model.

Figure 2.6-1: SCE A-Bank load model



<u>Behind-the-meter PV (BTM-PV)</u>

BTM-PV will be modeled as a component of the load model. Using the DG field on the PSLF load model the total nameplate capacity of the DG will be represented under PDGmax field, and the actual output will be based on the scenario. The total nameplate capacity is specified by the CEC, the allocation and location for projected DG is derived from the latest DRP filed with the CPUC as provided by Distribution Planning.

2.6.2.3 San Diego Gas and Electric Service Area

The substation load forecast reflects the actual, measured, true maximum coincident load on the substation distribution transformer(s). This maximum load is obtained either from SCADA historical data or in a few cases other sources (i.e. transmission data, meter data or legacy systems). If a correlation of load to weather is found, that measured maximum load is then weather normalized (i.e. value you expect 5 out of 10 years) as well as adversed (i.e. value you expect 1 out of 10 years) to produce a weather adjusted substation load. The weather adjusted substation load, is then adjusted based on location specific values such as, load growth from special allocation and DER growth, both utilizing the 2016 California Energy Demand Updated issued by the CEC. Additionally, an adjustment is made for the removal of the largest generation at the substation which was on during peak (generation larger than 500kW) and economic variables. The final distribution substation values are then adjusted across SDG&E so that area loads plus losses sum to the CEC 90/10 forecast. Thus, two substation loads for each distribution bus are modeled: the non-coincident load, and the coincident load.

The distribution substation annual forecast submitted to transmission planning is a non-coincident adverse peak forecast. The distribution substation forecast will always be higher than the system forecast which is a coincident forecast that is adjusted to a peak that would be expected 1 out of 10 years.

Behind-the-meter PV (BTM-PV)

BTM-PV will be modeled as a component of the load model. Using the DG field on the PSLF load model the total nameplate capacity of the DG will be represented under PDGmax field, and the actual output will be based on the scenario. The total nameplate capacity is specified by the CEC, the allocation and location for projected DG is derived from the latest DRP filed with the CPUC as provided by Distribution Planning.

2.6.2.4 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.

2.6.2.5 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.

2.6.3 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 basecases (2 year and 5 year out). For the long term basecase (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 year 2021. 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.

2.6.4 Self-Generation

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 self-generation PV capacity is projected to reach 22,655 MW in the mid demand case by 2031. In 2021-2022 TPP base cases, baseline PV generation production will be modeled explicitly. The CEDU 2020-2030 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 2,820 MW in the mid demand case by 2031. Behind-the-meter storage will not be modeled explicitly in 2021-2022 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.

PV Self-generation installed capacity for mid demand scenario by PTO and forecast climate zones are shown in Table 2.6-1. Output of the self-generation 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 forecast climate zones is shown in Table 2.6-2. These resources will be netted to load in the 2021-2022 TPP base cases,

Table 2.6-1: Mid demand baseline PV self-generation installed capacity by PTO[15]

PTO	Forecast Climate Zone	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
PGE	Central Coast	557	646	739	832	925	1018	1109	1199	1289	1378	1468
	Central Valley	1425	1569	1720	1869	2015	2156	2290	2418	2542	2663	2781
	Greater Bay Area	1538	1692	1860	2032	2202	2351	2486	2612	2731	2847	2959
	North Coast	403	443	485	526	565	602	634	663	690	715	738
	North Valley	316	339	365	390	413	435	455	475	494	512	530
	Southern Valley	1660	1815	1975	2132	2282	2424	2562	2696	2829	2961	3092
	PG&E Total	**5899**	**6504**	**7144**	**7781**	**8402**	**8986**	**9536**	**10063**	**10575**	**11076**	**11568**
SCE	Big Creek East	415	453	492	529	563	594	621	646	671	694	717
	Big Creek West	256	286	319	353	386	418	447	475	500	525	548
	Eastern	980	1099	1214	1322	1425	1522	1613	1701	1788	1873	1959
	LA Metro	1528	1718	1918	2120	2323	2517	2699	2867	3023	3170	3310
	Northeast	766	869	986	1106	1224	1339	1452	1563	1671	1779	1886
	SCE Total	**3945**	**4425**	**4929**	**5430**	**5921**	**6390**	**6832**	**7252**	**7653**	**8041**	**8420**
SDGE	SDGE	**1641**	**1784**	**1924**	**2050**	**2164**	**2266**	**2359**	**2444**	**2522**	**2597**	**2667**
CAISO Total		**11485**	**12713**	**13997**	**15261**	**16487**	**17642**	**18727**	**19759**	**20750**	**21714**	**22655**

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

Table 2.6-2: Mid demand baseline behind-the-meter storage installed capacity by PTO[16]

Year	BTM-Storage-Type	PGE-Zones						PG&E Total	SCE-Zones					SCE Total	SDGE Total	CAISO Total
		C. Coast	C. Valley	Bay Area	North Coast	North Valley	Southern Valley		Big Creek East	Big Creek West	Eastern	LA Metro	North east			
2021	Res	15	25	75	24	5	10	**154**	3	13	20	48	14	**98**	**62**	**314**
	Non-Res	11	32	37	11	2	20	**113**	10	7	15	122	37	**191**	**51**	**355**
2022	Res	19	31	94	30	6	12	**192**	4	17	25	62	18	**126**	**80**	**398**
	Non-Res	15	43	50	16	3	32	**159**	15	9	20	148	46	**238**	**63**	**460**
2023	Res	24	37	114	36	7	14	**232**	5	20	31	78	22	**156**	**98**	**486**
	Non-Res	20	54	63	21	4	44	**206**	20	10	26	173	56	**285**	**76**	**567**
2024	Res	30	44	136	42	9	17	**278**	5	24	38	94	27	**188**	**118**	**584**
	Non-Res	25	65	76	25	6	56	**253**	25	12	31	199	65	**332**	**88**	**673**
2025	Res	35	51	159	49	10	20	**324**	6	29	44	112	32	**223**	**138**	**685**
	Non-Res	30	76	89	30	7	68	**300**	30	14	36	224	75	**379**	**100**	**779**
2026	Res	42	59	183	56	11	23	**374**	7	33	51	132	37	**260**	**160**	**794**
	Non-Res	35	87	102	35	8	80	**347**	35	16	41	250	84	**426**	**112**	**885**
2027	Res	49	67	208	63	13	26	**426**	8	38	59	152	43	**300**	**182**	**908**
	Non-Res	40	99	115	40	9	92	**395**	40	17	47	276	94	**474**	**124**	**993**
2028	Res	56	75	235	71	14	29	**480**	9	43	67	173	49	**341**	**204**	**1025**
	Non-Res	45	110	128	45	11	104	**443**	45	19	52	301	103	**520**	**136**	**1099**
2029	Res	63	83	262	79	16	32	**535**	10	48	75	195	55	**383**	**228**	**1146**
	Non-Res	50	121	141	49	12	116	**489**	50	21	57	327	113	**568**	**148**	**1205**
2030	Res	71	92	290	87	18	36	**594**	11	54	83	218	62	**428**	**252**	**1274**
	Non-Res	55	132	154	54	13	128	**536**	55	23	63	352	123	**616**	**160**	**1312**
2031	Res	80	101	319	95	19	39	**653**	11	60	92	242	69	**474**	**276**	**1403**
	Non-Res	59	143	167	59	15	140	**583**	60	24	68	378	132	**662**	**172**	**1417**

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

2.7 Generation Assumptions

2.7.1 New Generation Projects

In addition to generators that are already in-service, new generators will be modeled in the studies as generally described below. Depending on the status of each project, new generators will be assigned to one of the three levels below:

- Level 1: Under construction (for Years 1-5 study case with applicable in-service dates)
- Level 2: Regulatory approval but not yet under construction (i.e., having Power Purchase Agreement approved by the CPUC or other regulatory agencies with applicable in-service dates for Year 5)
- Level 3: CPUC Base Portfolio generation, or planned resources in the IRP (for entity outside of California) for the 10-year study case (or for 6-10 year case with applicable in-service dates)

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

Up to 1-year Operating Cases:

- Level 1 generation with a planned in-service date within the time frame of the study.

2-5-year Planning Cases:

- Level 1 generation with a planned in-service date within the 2-5 year time frame of the study.
- Level 2 can be modeled if the contract has specific commercial operating dates within the 2-5 year time frame of the study.

6-10-year Planning Cases:

- Level 1 generation with a planned in-service date within the 2-5 year time frame of the study.
- Level 2 can be modeled if the contract has specific commercial operating dates within the 2-5 year time frame of the study.
- Level 3 generation with a planned in-service date within the time frame of the study.

2.7.2 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 sensitivity portfolios, which are used in the policy-driven assessment that is covered in section 3. The generic base portfolio resources will be modeled in the 2031 base cases.

The CPUC has issued a Decision17 recommending transmittal of a base portfolio along with two sensitivity portfolios for use in the 2021-2022 TPP. The base portfolio is designed to meet the 46 million metric ton greenhouse gas emissions target by 2031. The portfolios are developed using the RESOLVE resource optimization model assuming resources under development with CPUC-approved contracts to be part of the baseline assumptions. The CAISO will model the baseline resources in the study cases based on their in service dates 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 2021.

The base portfolio is comprised generic wind, solar, geothermal, pumped hydro and battery storage resources. Generic non-battery resources selected as portfolio resources are at a geographic scale that is too broad for transmission planning purpose which requires specific interconnection locations. Generic battery storage resources selected by the model are not tied to a location. CPUC staff, in collaboration with CEC and CAISO staff, has mapped both the battery and non-battery resources in the portfolios to the substation busbar level for use in the CAISO's 2021-2022 TPP.

Table 2.7-1 and Table 2.7-2 provide non-battery and battery resources in the base portfolio, respectively, complete with busbar mapping.

[17] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M366/K426/366426300.PDF

Table 2.7-1: 2021-2022 TPP base portfolio generic non-battery resources (2031)[18]

RESOLVE Resource	Tx Deliv. Zone	Substation	Base Portfolio
Arizona_Solar	SCADSNV-Riverside_Palm_Springs	Hassayampa 500kV	871
		Delaney-Colorado 500kV	1,482
Carrizo Wind	SPGE-Kern Greater Carrizo-Carrizo	Templeton 230kV	187
Carrizo Solar	SPGE-Kern Greater Carrizo-Carrizo	Mesa 115 kV*	55
Central Valley N. Los Banos Wind	Central Valley North Los Banos-SPGE	Los Banos 230kV	173
Greater_Imperial_Solar	Greater_Imperial-SCADSNV	Imperial Valley 230kV	333
		Ocotillo Express 230kV	215
Humboldt Wind	Sacramento River-Humboldt	Bridgeville 115kV	34
Kern_Greater_Carrizo_Solar	SPGE-Kern_Greater_Carrizo	Arco 230kV	144
		Midway 230kV	140
		Renfro 115kV	143
		Stockdale 230kV	144
		Wheeler Ridge 230kV	129
		Lamont 115 kV*	106*
Kern Greater Carrizo Wind	SPGE-Kern Greater Carrizo	Cholame 70 kV	20
Mountain_Pass_El_Dorado_Solar	Mountain_Pass_El_Dorado	El Dorado 230kV	83
		EL Dorado 500kV	165
North_Victor_Solar	North_Victor-Greater_Kramer	Victor 230kV	215
		Coolwater 230kV	85
Northern_California_Ex_Wind	Sacramento_River	Glenn 230kV	354
		Delevan 230kV	83
		Thermalito 230kV	178
		Rio Oso 230kV	152
Pisgah_Solar	Pisgah	Calcite	140
		Lugo	47
		Pisgah 230kV	14
SCADSNV Solar	SCADSNV	Mohave 500kV	568
Solano Geothermal	Solano-Sacramento River	Sonoma 3 230kV	51
Solano_Wind	Solano-Sacramento_River	Lakeville 230kV	194
		Tulucay 230kV	20
		Vaca-Dixon & GC Yard 500kV	146
		Shilo III 230kV	72
		Lone Tree 230kV	30
Southern_Nevada_Solar	SCADSNV-GLW_VEA	Innovation 230kV	445
		Desert View 230kV	344
		Crazy Eyes 230kV	1,234
Tehachapi_Solar	Tehachapi	WindHub 230kV	1,153
		Whirlwind 500kV	1,277
		Antelope 230kV	1,247
		Vincent 230kV	1,003
Tehachapi Wind	Tehachapi	WindHub 230kV	275
Westlands_Solar	Central_Valley_North_Los_Banos-SPGE	Gates 230kV	151
		Helm 230kV	176
		Henrietta 230kV	163
		Mc Call 230kV	204
		Mc Mullin 230kV	190
		Panoche 230kV	160
		Gates 500kV*	218
Pumped Hydro Storage	Pumped Hydro Storage	Lee Lake 500kV	313
		Sycamore Canyon 230kV	314
Baja California Wind	Greater Imperial-SCADSNV	East County 500kV	495
Greater Imperial Geothermal	Greater Imperial-SCADSNV	Bannister	600

[18] https://caenergy.databasin.org/documents/documents/a618da529cd346dfa5bec12148161b71/

RESOLVE Resource	Tx Deliv. Zone	Substation	Base Portfolio
New_Mexico_Wind[19]	SCADSNV-Riverside_Palm_Springs	Palo Verde 500kV	
Wyoming_Wind	SCADSNV-Mountain_Pass_El_Dorado	El Dorado 500kV	1,062
NW_Ext_Tx_Wind	Sacramento_River	Round Mountain 500kV	530
Portfolio Total (non-battery)			**18,327**

* In coordination with the CPUC, adjustments were made to the final mapping of co-located solar-battery resources to accommodate the need for 155 MW of battery storage at Mesa, Lamont and Kettleman identified in the 2020-2021 transmission plan. Accordingly, 161 MW of co-located solar, along with 155 MW of storage, was moved from Gates 500 kV to Mesa and Lamont substations.

Table 2.7-2: 2021-2022 TPP base portfolio generic battery resources (2031)[20]

Substation Name	Tx Deliv. Zone	Base Portfolio (MW)
Antelope 230kV	Tehachapi	575
Panoche	SPGE_Z1_Westlands	99
Birds Landing	Norcal_Z4_Solano	5
Gates 230kV	SPGE_Z1_Westlands	136
Delaney	SCADSNV_Z4_RiversideAndPalmSprings	426
Vincent	Tehachapi	809
Windhub	Tehachapi	1,008
Whirlwind 230kV	Tehachapi	1,645
Gates 500kV*	SPGE_Z1_Westlands	186
Victor	GK_Z3_NorthOfVictor	50
Hassayampa	SCADSNV_Z4_RiversideAndPalmSprings	269
Mohave 500kV	SCADSNV_Z5_SCADSNV	228
Calcite	GK_Z4_Pisgah	126
Innovation	SCADSNV_Z2_GLW_VEA	123
Eldorado 230kV	SCADSNV_Z1_EldoradoAndMtnPass	75
Eldorado 500kV	SCADSNV_Z5_SCADSNV	149
Crazy Eyes	SCADSNV_Z2_GLW_VEA	125
Mesa 115 kV*	SPGE-Carrizo	50
Lamont 115*	SPGE-Kern	95
Kettleman*	SPGE_Z1_Westlands	10
Gold Hill	NorCalOutsideTxConstraintZones	59
Martin	NorCalOutsideTxConstraintZones	250
Walnut	TehachapiOutsideTxConstraintZones	200
Hinson	TehachapiOutsideTxConstraintZones	200
Etiwanda	KramerInyoOutsideTxConstraintZones	101
Laguna Bell	TehachapiOutsideTxConstraintZones	500

[19] See the policy-driven assessment section for the treatment of New Mexico vs. Wyoming wind.

[20] ftp://ftp.cpuc.ca.gov/energy/modeling/Battery_Mapping_Dashboard_All_Portfolios_Final.xlsx

Substation Name	Tx Deliv. Zone	Base Portfolio (MW)
Walnut	TehachapiOutsideTxConstraintZones	200
Silvergate	GreaterImpOutsideTxConstraintZones	200
Moorpark	TehachapiOutsideTxConstraintZones	500
Escondido	GreaterImpOutsideTxConstraintZones	50
Sycamore Canyon	GreaterImpOutsideTxConstraintZones	300
Talega 138kV	GreaterImpOutsideTxConstraintZones	200
Trabuco 138kV	GreaterImpOutsideTxConstraintZones	250
Encina 138kV	GreaterImpOutsideTxConstraintZones	160
Kearny	GreaterImpOutsideTxConstraintZones	10
	Total	**9,368**

* In coordination with the CPUC, adjustments were made to the final mapping of co-located solar-battery resources to accommodate the need for 155 MW of battery storage at Mesa, Lamont and Kettleman identified in the 2020-2021 transmission plan. Accordingly, 155 MW of co-located storage, along with 161 MW of solar, was moved from Gates 500 kV to Mesa, Lamont and Kettleman substations.

2.7.3 Thermal generation

For the latest updates on new generation projects, please refer to the CEC website under the licensing section (http://www.energy.ca.gov/sitingcases/all_projects.html). 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.

2.7.4 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.

2.7.5 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 off-line based on the OTC compliance dates,

Once Through Cooled Retirements – As identified in section 3.7.6.

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

Other Retirements – The ISO will not assume retirement based on resource age of 40 years or more in order to align with the latest CPUC portfolio information.

2.7.6 OTC Generation

Modeling of the once-through cooled (OTC) generating units follows the compliance schedule from the SWRCB's Policy on OTC plants with the following exception:

- Generating units that are repowered, replaced or having firm plans to connect to acceptable cooling technology, as illustrated in Table A2 in Appendix A. This table also includes retirements of some OTC generating units to accommodate repowering projects, which received the CPUC approval for the Power Purchase and Tolling Agreements (PPTAs) and as well as the certificate to construct and operate from the CEC.
- All other OTC generating units will be modeled off-line beyond their compliance dates or planned retirement dates provided by the generating owners except for the units that have been approved for compliance schedule extension by the State Water Resources Control Board [21] for helping to meet CAISO's system capacity need for the 2021-2023 timeframe;
- Generating units with acceptable Track 2[22] mitigation plan that was approved by the State Water Resources Control Board.

2.7.7 Distribution connected resources modeling assumption

Table 2.7-3 below outlines modeling assumptions for distribution connected resources in the TPP base cases.

Table 2.7-3: Modeling assumptions of distribution connected resources

[21] https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_policy_2020/otc2020.pdf

[22] Track 2 requires reductions in impingement mortality and entrainment to a comparable level to that which would be achieved under Track 1, using operational or structural controls, or both (https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/rs2015_0018.pdf).

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

2.8 Preferred Resources[23]

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. The CAISO received a submission from the Public Advocates Office related to offshore wind. The CAISO will be conducting an offshore wind study as defined in the sensitivity study provided by the CPUC for the Policy Assessment, in section 3.

2.8.1 Methodology

The CAISO issued a paper[24] 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 2019-2020 planning cycle, 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 amounts as projected by the CEC, distributed generation based on the CPUC Default RPS Portfolio and a mix of preferred resources including energy storage based on the CPUC LTPP 2012 local capacity 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

[23] 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.

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

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 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[25]. The CAISO will continue to use the methodology developed as part of the study to evaluate these types of resources.

As part of the 2020-2021 IRP, 9,368 MW of storage was provided in the base portfolio as listed in Table 2.7-2 and will be modeled in the year 2031 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[26].

2.8.2 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.[27] 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 commit after the

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

[26] 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

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

https://www.caiso.com/Documents/Presentation_JointISO_CPUCWorkshopSlowResponseLocalCapacityResourceAssessment_Oct42017.pdf 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 2.8-1 describes supply-side DR capacity assumptions for the three IOUs.

Table 2.8-1: Existing DR Capacity Range for Each IOU Load Serving Entities within CAISO BA

PG&E

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)	236	System-wide SubLAP RDRR	30 minutes
Capacity Bidding Program (CBP)	36	System-wide SubLAP PDR	Day Ahead
Peak Day Pricing (PDP)	4.2	System-wide	Day Ahead
SmartRate™	5.5	System-wide	Day Ahead
SmartAC™	34	System-wide SubLAP Selected 21 Substations PDR	None required
DRAM	NA		>30 Minutes
Total	316		

SCE

SCE Portfolio-Adjusted DR Load Impacts for CAISO Peaking Conditions, August,1-in-2 Weather			
Supply-side DR (MW)	**MW**	**Market Model/Level of Dispatch**	**Response time**
Base Interruptible Program 15 Minute (BIP-15)	168	RDRR- System-wide, Sublap, A-Bank	20 Minutes or Less
Base Interruptible Program 30 Minute (BIP-30)	375	RDRR- System-wide, Sublap, A-Bank	30 Minutes
Agricultural and Pumping Interruptible (API)	31	RDRR- A-bank	20 Minutes or Less
Summer Discount Plan Residential (SDP-R)	150	PDR-A-bank	20 Minutes or Less
Summer Discount Plan Commercial (SDP-C)	18	PDR- System-wide, Sublap, A-Bank	20 Minutes or Less
Smart Energy Program	38	PDR- System-wide, Sublap, A-Bank	20 Minutes or Less

Capacity Bidding Program Day-Ahead (CBP-DA)	4	PDR- System-wide, Sublap	Day Ahead
Capacity Bidding Program Day-Of (CBP-DO)	4	PDR- System-wide, Sublap	> 30 Minutes
DRAM	100	PDR- System-wide, Sublap	>30 Minutes
Total	888		

SDG&E[28]

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)	0.89	System-wide SubLAP RDRR	20 minutes
Capacity Bidding Program (CBP)	3.43	System-wide SubLAP PDR	>30 Minutes
Critical Peak Pricing (CPP)[29]	7.18	System-wide PDR	>30 Minutes
AC Saver – Day Ahead	7.82	System-wide PDR	>30 Minutes
AC Saver – Day Of	2.42	System-wide PDR	>30 Minutes
DRAM (demonstrated capacity)	12.77	System-wide PDR	>30 Minutes
Total	34.51		

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 2.8-2 will be applied to the DR projections to account for avoided distribution losses.

Table 2.8-2: Factors to Account for Avoided Distribution Losses

	PG&E	SCE	SDG&E
Distribution loss factors	1.067	1.051	1.071

[28] Based on last year's information. SDG&E DR modeling will be updated based on the latest information from SDGE.

[29] Similar to Peak Day Pricing

2.8.3 Energy Storage

The CAISO models the existing, under construction and/or approved procurement status energy storage projects in the reliability basecases. For the purpose of this table, colocated resources have their own respective market IDs as compared to hybrid resources that have a single market id. The ISO relies on multiple sources, including but not limited to PTO inputs, CEC forecast and generation interconnection queue to update the numbers in the table 2.8-3.

Table 2.8-3: IOU Existing and Proposed Energy Storage Procurement[30]

PTO	Category	In-service	Under Construction / Approved Procurement			Total
			2023	2026	2031	
PG&E	Transmission(Stand alone and colocated)	0	892.5	0	0	892.5
	Front of the meter Distribution including colocated	6.5	20	0	0	26.5
	Behind the meter Customer (Residential and Non-Residential)	359	439	721	1236	2755
	Hybrid Generation	0	0	0	0	0
SCE	Transmission(Stand alone and colocated)	100	100	100	0	300
	Front of the meter Distribution including colocated	65	235	0	0	300
	Behind the meter Customer (Residential and Non-Residential)	475	441	687	1136	2739
	Hybrid Generation	0	0	0	0	0
SDG&E	Transmission(Stand alone and colocated)	104	816.1	0	0	920.1
	Front of the meter Distribution including colocated	50.08	0	0	0	50.08
	Behind the meter Customer (Residential and Non-Residential)	59.3	0	0	448	507.3
	Hybrid Generation	0	0	0	0	0
Total		**1219**	**2944**	**1508**	**2820**	**8490**

[30] Final 2018 CEC IEPR Update Volume II https://www.energy.ca.gov/2018_energypolicy/documents

In November 2019, the CPUC adopted D.19-11-016, which ordered the procurement of 3,300 MW of resource adequacy capacity by 2023 and recommended the extension of several once-through-cooling (OTC) thermal generators for system reliability. Neither the 3,300 MW of procurement nor the OTC extensions were modeled as part of the baseline of the reference system plan (RSP) adopted in this decision. This RSP identifies a need consistent with the near-term procurement order in D.19-11-016, and vice versa. Many of these new resources that comprise the 3,300 MW are anticipated to be battery energy storage system based on the proposed bi-lateral contracts submitted by the Load Serving Entities.

These storage capacity amounts will be modeled in the initial reliability base cases using the locational information as well as the in-service dates provided by CPUC.

2.9 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 2.9-1 lists the capability and power flows that will be modeled in each scenario on these paths in the northern area assessment[31].

Table 2.9-1: 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)	4000[33]	Summer Peak
PDCI (N-S)	3220[34]	
Path 66 (N-S)	4800[35]	
Path 15 (N-S)	-5400[36]	Spring Off Peak
Path 26 (N-S)	-3000	
PDCI (N-S)	-1000[37]	
Path 66 (N-S)	-3675	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

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

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 3210 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.

36 May not be achievable under certain system loading conditions

37 Current operational limit in the south to north direction is 1000 MW.

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.

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.

Table 2.9-2: Major Path flows in southern area (SCE and SDG&E system) assessment

Path	Transfer Capability/SOL (MW)	Near-Term Target Flows (MW)	Scenario in which Path will be stressed, if applicable
Path 26 (N-S)	4,000	4,000	Summer Peak
Path 26 (N-S)	3,000	0 to 3,000	Spring Off Peak
PDCI (N-S)	3220[38]	3220[39]	Summer Peak
West of River (WOR)	11,200	5,000 to 11,200	Summer Peak
East of River (EOR)	10,100	4,000 to 10,100	Summer Peak
San Diego Import	2765~3565	2,400 to 3,500	Summer Peak
SCIT	17,870	15,000 to 17,870	Summer Peak
Path 45 (N-S)	600[40]	0 to 408	Summer Peak
Path 45 (S-N)	800	0 to 300	Spring Off Peak

2.10 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/thegrid/operations/opsdoc/index.html for the list of publicly available Operating Procedures.

[38] Current operational limit is 3210 MW.

[39] Ibid.

[40] Path 45 north-to-south is currently rated at 408 MW and expected to be uprated to 600 MW for summer season by summer on 2020

2.11 Study Scenario

2.11.1 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 4.7.

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 2.11-1 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 4.9 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 2.11-1.

Table 2.11-1: Summary of Base Scenario Studies in the CAISO Reliability Assessment

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2023	2026	2031
Northern California (PG&E) Bulk System	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak Winter Off-Peak
Humboldt	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak Winter peak Spring Off-Peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter peak
North Valley	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Central Valley (Sacramento, Sierra, Stockton)	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Greater Bay Area	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF Only)
Greater Fresno	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Kern	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Central Coast & Los Padres	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
Southern California Bulk transmission system	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak
SCE Metro Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE Northern Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE North of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE East of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE Eastern Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SDG&E main transmission	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SDG&E sub-transmission	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Valley Electric Association	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak

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

The data in the table 2.11-2, 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 2.11-2: Baseline Scenario Definitions and Renewable Generation Dispatch

PTO	Scenario	Day/Time			BTM-PV			Transmission Connected PV			Transmission Connected Wind			% of managed peak load[41]		
		2023	2026	2031	2023	2026	2031	2023	2026	2031	2023	2026	2031	2023	2026	2031
PG&E	Summer Peak	7/27 HE 18	See CAISO	See CAISO	21%	See CAISO	See CAISO	10%	See CAISO	See CAISO	62%	See CAISO	See CAISO	100%	See CAISO	See CAISO
PG&E	Spring Off Peak	4/26 HE 20	See CAISO	See CAISO	0%	See CAISO	See CAISO	0%	See CAISO	See CAISO	55%	See CAISO	See CAISO	71%	See CAISO	See CAISO
PG&E	Winter Off peak	N/A	N/A	11/9 HE 5	N/A	N/A	0%	N/A	N/A	0%	N/A	N/A	12%	N/A	N/A	46%
PG&E	Winter peak	12/11 HE 19	12/14 HE 19	12/9 HE 19	0%	0%	0%	0%	0%	0%	13%	13%	13%	75%	76%	78%
SCE	Summer Peak	9/5 HE 16	9/1 HE 16	9/3 HE 19	46%	46%	0%	51%	51%	0%	20%	20%	40%	100%	100%	100%
SCE	Spring Off Peak	4/26 HE 20	See CAISO	See CAISO	0%	See CAISO	See CAISO	0%	See CAISO	See CAISO	48%	See CAISO	See CAISO	65%	See CAISO	See CAISO
SDG&E	Summer Peak	9/6 HE 19	9/2 HE 19	9/4 HE 19	0%	0%	0%	0%	0%	0%	33%	33%	33%	100%	100%	100%
SDG&E	Spring Off Peak	5/23 HE 20	See CAISO	See CAISO	0%	See CAISO	N/A	0%	See CAISO	N/A	68%	See CAISO	N/A	75%	See CAISO	N/A
VEA	Summer Peak	9/5 HE 16	9/1 HE 16	9/3 HE 19	N/A	N/A	N/A	51%	51%	0%	N/A	N/A	N/A	100%	100%	100%
VEA	Spring Off Peak	4/26 HE 20	See CAISO	See CAISO	N/A	N/A	N/A	0%	See CAISO	See CAISO	N/A	N/A	N/A	65%	See CAISO	See CAISO

[41] The data is based on 2030 information. ISO will update with 2031 data once available.

PTO	Scenario	Day/Time	BTM-PV			Transmission Connected PV [42]			Transmission Connected Wind			% of non-coincident PTO managed peak load		
			PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE
CAISO	2031 Summer Peak	9/2 HE 19	6%	0%	0%	0%	0%	0%	42%	40%	33%	96%	100%	98%
	2031 Spring Off Peak	4/6 HE 13	79%	80%	85%	92%	94%	95%	20%	34%	30%	16%	17%	7%
	2026 Summer Peak	9/1 HE 19	6%	0%	0%	0%	0%	0%	42%	40%	33%	95%	99%	98%
	2026 Spring Off Peak	4/5 HE 13	79%	79%	86%	92%	94%	95%	20%	34%	30%	24%	23%	13%

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

[42] The transmission connected PV in the 2031 Spring Off Peak case might be curtailed down to limit the export within acceptable range.

2.11.3 Sensitivity Studies

In addition to the base scenario studies that the CAISO will be assessing in the reliability analysis for the 2021-2022 transmission planning process, the CAISO will also be conducting sensitivity studies identified in Table 2.11-3. 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 2.11-3: Summary of Sensitivity Studies in the CAISO Reliability Assessment

Sensitivity Study	Near-term Planning Horizon		Long-term Planning Horizon
	2023	2026	2031
Summer Peak with high CEC forecasted load	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	
Off 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 Main	-	
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 Main	-	
Summer Peak with high San Jose and SVP load			PG&E Greater Bay Area
Summer Peak with forecasted load addition	VEA Area	VEA Area	
Summer Off peak with heavy renewable output	-	VEA Area	

2.11.4 Sensitivity Scenario Definitions and Renewable Generation Dispatch

Table 2.11-4: 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	2023 Summer Peak	21%	99%	10%	99%	62%	62%	Solar and wind dispatch increased to 20% exceedance values
	Off peak with heavy renewable output and minimum gas generation commitment	2023 Spring Off-peak	0%	99%	0%	99%	20%	64%	Solar and wind dispatch increased to average of 20% exceedance values
	Summer Peak with high CEC forecasted load	2026 Summer Peak	6%	6%	0%	0%	42%	42%	Load increased by turning off AAEE
	Summer Peak with high San Jose and SVP load	2031 Summer Peak	0%	0%	0%	0%	42%	42%	Model additional retail and wholesale load information on top of the CEC forecast for the case
SCE	Summer Peak with heavy renewable output and minimum gas generation commitment	2023 Summer Peak	46%	91%	51%	99%	20%	67%	Solar and wind dispatch increased to 20% exceedance values
	Off peak with heavy renewable output and minimum gas generation commitment	2023 Spring Off-peak	0%	91%	0%	99%	48%	67%	Solar and wind dispatch increased to 20% exceedance values
	Summer Peak with high CEC forecasted load	2026 Summer Peak	6%	6%	0%	0%	40%	40%	Load increased per CEC high load scenario
SDG&E	Summer Peak with heavy renewable output and minimum gas generation commitment	2023 Summer Peak	0%	96%	0%	96%	33%	51%	Solar and wind dispatches increased to 20% exceedance values
	Off peak with heavy renewable output and minimum gas generation commitment	2023 Spring Off-peak	0%	96%	0%	96%	68%	51%	Solar and wind dispatches increased to 20% exceedance values with net load unchanged at 57% of summer peak
	Summer Peak with high CEC forecasted load	2026 Summer Peak	0%	0%	0%	0%	33%	33%	Load increased per CEC high load scenario
VEA	Summer Peak with forecasted load addition	2023 Summer Peak			51%	51%			Load increase reflect future load service request
	Off-peak with heavy renewable output	2026 Spring Off-peak			0%	96%			Modeled active GIDAP projects in the queue
	Summer Peak with forecasted load addition	2026 Summer Peak			21%	21%			Load increase reflect future load service request

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

2.12 Study Base Cases

The power flow base cases from WECC will be used as the starting point of the CAISO transmission plan base cases. Table 2.12-1 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)[43] 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 2.12-1: Summary of WECC Base Cases used to represent system outside CAISO

Study Year	Season	WECC Base Case	Year Published
2023	Summer Peak	2023 Heavy Summer 3	11/25/2020
	Winter Peak	2022-23 Heavy Winter 2	6/19/2020
	Spring Off-Peak	2021 Heavy Spring 1	4/3/2020
2026	Summer Peak	2026 Heavy Summer 2	7/31/2020
	Winter Peak	2025-26 Heavy Winter 2	9/1/2020
	Spring Off-Peak	2024 Light Spring 1	5/1/2020
2031	Summer Peak	2031 Heavy Summer 1	10/19/2020
	Spring Off-Peak	2030 Light Spring 1	12/9/2019

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 represent the conditions outlined in the Study Plan. For example, a 2024 summer peak base case for the northern California will use 24HS2a1 base case from WECC as the starting point. However, the network representation in northern California will be updated with the latest information

[43] 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.

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.

2.13 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 3.1.3, 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)[44][45]
- 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)[46]
- 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)

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)

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

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[47] (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.

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

2.13.1 Known Outages

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.

Any issues or conflicts identified with planned outages in the assessment described above will be documented in the IRO-017 Requirement R4[48] Planned Outage Mitigation Plan in addition to the transmission plan.

Table 2.13-1 provides the known scheduled outages involving multiple facilities satisfying the criteria's mentioned above that are selected for assessment in the current transmission planning cycle based on information obtained from TOs and TOPs.

Table 2.13-1: Known outages involving multiple facilities selected for assessment[49]

PTO Area	Scheduled Outage Involving Multiple Facilities	Facilities Affected	Additional Description, If Needed
PG&E	None	None	
SCE	SONGS 220 kV Bus Section	The 220 kV facilities that the bus connects to	
SCE	Sylmar Bank outage	The 220 kV buses that the bank directly connects to	
SCE	Victor 220 kV Bus Outage	North or South 220 kV Bus	
SCE	Lugo 220 kV Bus Outage	East or West 220 kV Bus	

48 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.

49 ISO will continue to work with PTOs to add and assess any other relevant outages during the course of the assessment.

PTO Area	Scheduled Outage Involving Multiple Facilities	Facilities Affected	Additional Description, If Needed
SCE	Lugo 500 kV Bus Outage	East or West 500 kV Bus	
SCE	Devers 220 kV Bus Outage	North or South 220 kV Bus	
SCE	Magunden 220 kV Bus Outage	North or South 220 kV Bus	
SDG&E	San Onofre 230kV Bus Sections Scheduled Maintenance Outage	230kV Bus Sections	The ISO will review applicable operating criteria to determine whether the scheduled maintenance outage for San Onofre 230kV bus sections still causes operational concerns.
SDG&E	TL666 and TL662 Reliability Project	TL662 and TL666 lines	Outage timeframe: June 2026

2.14 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 230 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.

2.14.1 Technical Studies

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

2.14.2 Steady State Contingency Analysis

The CAISO will perform power flow contingency analyses based on the CAISO Planning Standards[50] 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 4.1.6.

Depending on the type and technology of a power plant, several G-1 contingencies represent an outage of the whole power plant (multiple units)[51]. 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

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[50] California ISO Planning Standards are posted on the ISO website at http://www.caiso.com/Documents/ISOPlanningStandards-November22017.pdf

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

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.

2.14.3 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.

2.14.4 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.

2.14.5 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.

2.14.6 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.

2.14.7 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.

2.15 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. 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.

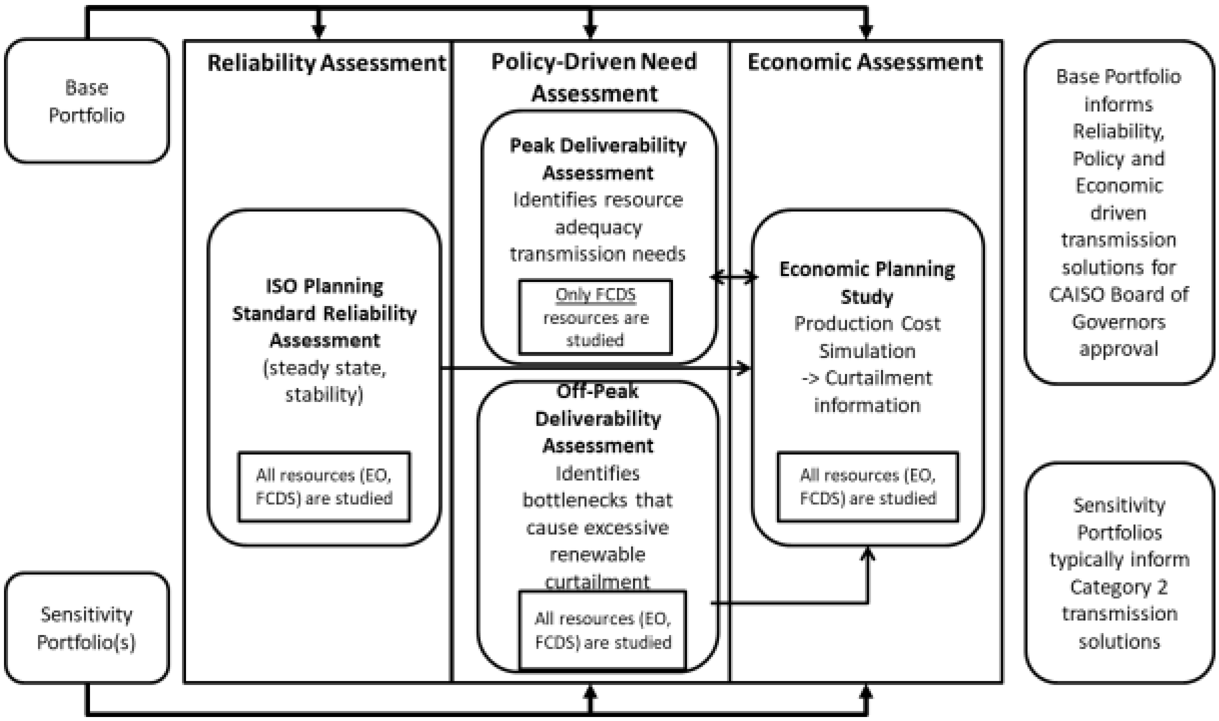
Evaluation of the need for policy-driven transmission elements begins in Phase 1 with the CAISO's specification, in the context of the unified planning assumptions and study plan, of the public policy objectives it proposes to adopt for transmission planning purposes in the current cycle. For the 2021-2022 planning cycle, the overarching public policy objective is the state's mandate for meeting renewable energy targets and greenhouse gas (GHG) reduction target by 2030 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 2030 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 for resource adequacy counting purposes to identify if there is sufficient transmission capability 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[52].

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.[53]

Production cost model simulation (PCM) study

[52] http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf

[53] http://www.caiso.com/Documents/Off-PeakDeliverabilityAssessmentMethodology.pdf

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 to be studied

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 has issued a Decision[54] recommending transmittal of a base portfolio along with two sensitivity portfolios for use in the 2021-2022 TPP. The decision is accompanied by a document entitled Modeling Assumptions for the 2021-2022 Transmission Planning Process which describes the methodology and results of the busbar mapping process and includes guidance for TPP studies[55].

CPUC staff develop the portfolios using the RESOLVE capacity expansion model. The portfolios are developed assuming resources under development with CPUC-approved contracts to be part of the baseline resource fleet. The CAISO will model baseline 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 2021.

The base portfolio is designed to meet the 46 MMT GHG emissions target by 2031. The first sensitivity portfolio is designed to meet a 38 MMT GHG target by 2031 while the second sensitivity portfolio is based on a 30 MMT GHG target and is intended to test the transmission needs associated with offshore wind. The portfolios consist of resources with Full Capacity (FC) and Energy Only (EO) deliverability status. 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.

The portfolios are comprised of generic wind, solar, geothermal, pumped hydro and battery storage resources and include some out-of-state resources. The sensitivity portfolios also include thermal generation capacity not retained[56].

Table 3.3-1 and Table 3.3-2 show the total (FCDS+EO) and FC generic resource mix in the three portfolios

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[54] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M366/K426/366426300.PDF

[55] ftp://ftp.cpuc.ca.gov/energy/modeling/Modeling_Assumptions_2021_22_TPP_Final.pdf

[56] RESOLVE reports the aggregate amount of thermal generation not retained by resource category. Unit-specific information is not modeled. Because the TPP studies require modeling of specific units, CPUC staff has provided information to the CAISO regarding which units should be assumed as retired. The information can be found at ftp://ftp.cpuc.ca.gov/energy/modeling/Retirement_List_for_Sensitivity_Portfolios.xlsx

Table 3.3-1: Total (FC+EO) resource mix in the three portfolios, MW (2031)

	Base	Sensitivity-1	Sensitivity-2
Solar	13,044	13,817	9,807
Wind	4,005	7,955	16,039
Pumped Hydro	627	1,843	1,495
Geothermal	651	105	0
Battery storage	9,368	9,447	7,604
Thermal retirements	0	(1,319)	(1,718)
Total (FC+EO)	**27,695**	**31,848**	**33,227**

Table 3.3-2: Full Capacity (FC) resource mix in the three portfolios, MW (2031)

Solar	1,832	2,422	1,332
Wind	3,971	6,451	13,250
Pumped Hydro	627	1,843	1,495
Geothermal	651	57	0
Battery storage	9,368	9,447	7,604
Thermal retirements	0	(1,319)	(1,718)
Total FC	**16,448**	**18,901**	**21,963**

The generic non-battery resources selected as portfolio resources are at a geographic scale that is too broad for transmission planning purposes which requires specific interconnection locations. In the case of generic battery storage the resources selected by the model are not tied to a location altogether. CPUC staff, in collaboration with CEC and CAISO staff, has mapped both the battery and non-battery resources in the portfolios to the substation busbar level for use in the 2021-2022 TPP.

Table 3.3-3 provides the total (FC+EO) and FC non-battery resources in the three portfolios complete with busbar mapping. Table 3.3-4 lists battery storage resources in the three portfolios, all of which are considered to have FC deliverability status.

Table 3.3-3: Total generic non-battery resources in the base and sensitivity portfolios (2031)[57]

			Base Portfolio (MW)		Sensitivity-1 (MW)		Sensitivity-2 (MW)	
RESOLVE Resource	Tx Deliv. Zone	Substation	Total	FCDS	Total	FCDS	Total	FCDS
Arizona_Solar	SCADSNV-Riverside_Palm_Springs	Hassayampa 500kV	871		600		707	
		Delaney-Colorado 500kV	1,482		981		1,203	
Carrizo_Wind	SPGE-Kern_Greater_Carrizo-Carrizo	Templeton 230kV	187	187	287	287	287	287
Carrizo_Solar	SPGE-Kern_Greater_Carrizo-Carrizo	Mesa 115 kV*	55		55		55	
Central_Valley_N._Los_Banos_Wind	Central_Valley_North_Los_Banos-SPGE	Los Banos 230kV	173	173	173	173	173	173
Greater_Imperial_Solar	Greater_Imperial-SCADSNV	Imperial Valley 230kV	333		697	365	697	365
		Ocotillo Express 230kV	215		451	235	451	235
Humboldt_Wind	Sacramento_River-Humboldt	Bridgeville 115kV	34		34		34	
Kern_Greater_Carrizo_Solar	SPGE-Kern_Greater_Carrizo	Arco 230kV	144		165			
		Midway 230kV	140		160			
		Renfro 115kV	143		164	21		
		Stockdale 230kV	144		165	21		
		Wheeler Ridge 230kV	129		147			
		Lamont 115 kV*	106		106		106	
Kern_Greater_Carrizo_Wind	SPGE-Kern_Greater_Carrizo	Cholame 70 kV	20	20	20	20	20	20
Mountain_Pass_El_Dorado_Solar	Mountain_Pass_El_Dorado	El Dorado 230kV	83		83		83	
		EL Dorado 500kV	165		165		165	
North_Victor_Solar	North_Victor-Greater_Kramer	Victor 230kV	215	159	215	159	215	159
		Coolwater 230kV	85	85	85	85	85	85
Northern_California_Ex_Wind	Sacramento_River	Glenn 230kV	354	354	354	354	354	354
		Delevan 230kV	83	83	83	83	83	83
		Thermalito 230kV	178	178	178	178	178	178
		Rio Oso 230kV	152	152	152	152	152	152
Pisgah_Solar	Pisgah	Calcite	140		140		140	
		Lugo	47	47	47	47	47	47
		Pisgah 230kV	14	14	14	14	14	14
Sacramento_River_Solar	Sacramento_River	Delevan 230kV			43			
		Glenn 230kV			47			
		Palmero 230kV			46			
		Rio Oso 230kV			49			
		Thermalito 230kV			46			
SCADSNV_Solar	SCADSNV	Mohave 500kV	568		740		410	
Solano_Geothermal	Solano-Sacramento_River	Sonoma 3 230kV	51	51	105	57		
Solano_Solar	Solano-Sacramento_River	Fulton 230kV			159			
		Contra Costa 230kV			156			
		Tulucay 230kV			137			
		Vaca-Dixon & GC Yard			170			
Solano_Wind	Solano-Sacramento_River	Lakeville 230kV	194	194	194	194	194	194
		Tulucay 230kV	20	20	20	20	20	20
		Vaca-Dixon & GC Yard	146	146	146	146	146	146
		Shilo III 230kV	72	72	72	72	72	72
		Lone Tree 230kV	30	30	30	30	30	30
Southern_Nevada_Solar	SCADSNV-GLW_VEA	Innovation 230kV	445		40		40	
		Desert View 230kV	344	106	31	31	31	31
		Crazy Eyes 230kV	1,234	242	111		111	
Southern_Nevada_Wind	SCADSNV-GLW_VEA	Innovation 230kV			97	97	97	97
		Desert View 230kV			75	75	75	75
		Crazy Eyes 230kV			270	270	270	270
Tehachapi_Solar	Tehachapi	WindHub 230kV	1,153		1,398		1,153	
		Whirlwind 500kV	1,277		1,549		1,277	
		Antelope 230kV	1,247	395	1,512	660	1,247	395
		Vincent 230kV	1,003		1,217		1,003	
Tehachapi_Wind	Tehachapi	WindHub 230kV	275	275	275	275	275	275
Westlands_Solar	Central_Valley_North_Los_Banos-SPGE	Gates 230kV	151		151			
		Helm 230kV	176	176	176	176		
		Henrietta 230kV	163	163	163	163		
		Mc Call 230kV	204	204	204	204		
		Mc Mullin 230kV	190	190	190	190		
		Panoche 230kV	160	50	160	50		
		Gates 500kV*	218		883		567	
Pumped Hydro Storage	Pumped Hydro Storage	Lee Lake 500kV	313	313	500	500	500	500
		Sycamore Canyon 230kV	314	314	500	500	500	500
		Red Bluff 500kV			843	843	495	495
Baja_California_Wind	Greater_Imperial-SCADSNV	East County 500kV	495	495	495	495	495	495
Greater_Imperial_Geothermal	Greater_Imperial-SCADSNV	Bannister	600	600				
New_Mexico_Wind	SCADSNV-Riverside_Palm_Springs	Palo Verde 500kV	Note[58]		1,500	1,500	1,500	1,392
Wyoming_Wind	SCADSNV-Mountain_Pass_El_Dorado	El Dorado 500kV	1,062	1,062	1,500	1,500	1,500	
NW_Ext_Tx_Wind	Sacramento_River	Round Mountain 500kV	530	530	1,500	530	1,500	587
SW_Ext_Tx_Wind	SCADSNV-Riverside_Palm_Springs	Palo Verde 500kV			500		234	
Diablo_Canyon_Offshore_Wind	N/A	Diablo Canyon 500kV					4,419	4,419
Humboldt_Bay_Offshore_Wind	N/A	Humboldt 230KV					1,607	1,607

57 https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442467917

58 The 1062 MW Wyoming_Wind mapped to Eldorado will also be studied as New_Mexico_Wind mapped at Paloverde 500 kV

Morro Bay Offshore Wind	N/A	Morro Bay 230kV					2,324	2,324
		Portfolio Total (non-battery)	**18,327**	**7,080**	**23,720**	**10,773**	**27,341**	**16,077**

* In coordination with the CPUC, adjustments were made to the final mapping of co-located solar-battery resources to accommodate the need for 155 MW of battery storage at Mesa, Lamont and Kettleman identified in the 2020-2021 transmission plan. Accordingly, 161 MW of co-located solar, along with 155 MW of storage, was moved from Gates 500 kV to Mesa and Lamont substations.

Table 3.3-4: Generic battery resources in the base and sensitivity portfolios (2031)[59]

Substation Name	Tx Deliv. Zone	Base Portfolio (MW)	Sensitivity 1 (MW)	Sensitivity 2 (MW)
Antelope 230kV	Tehachapi	575	575	575
Panoche	SPGE_Z1_Westlands	99	99	0
Wheeler Ridge	SPGE_Z2_KernAndGreaterCarrizo	0	16	0
Arco	SPGE_Z2_KernAndGreaterCarrizo	0	19	0
Midway 230kV	SPGE_Z2_KernAndGreaterCarrizo	0	18	0
Birds Landing	Norcal_Z4_Solano	5	0	0
Gates 230kV	SPGE_Z1_Westlands	136	136	0
Delaney	SCADSNV_Z4_RiversideAndPalmSprings	426	331	0
Vincent	Tehachapi	809	941	748
Windhub	Tehachapi	1,008	1,081	860
Whirlwind 230kV	Tehachapi	1,645	1,198	953
Gates 500kV*	SPGE_Z1_Westlands	186	186	500
Victor	GK_Z3_NorthOfVictor	50	50	50
Hassayampa	SCADSNV_Z4_RiversideAndPalmSprings	269	53	0
Mohave 500kV	SCADSNV_Z5_SCADSNV	228	369	98
Calcite	GK_Z4_Pisgah	126	126	126
Innovation	SCADSNV_Z2_GLW_VEA	123	36	36
Eldorado 230kV	SCADSNV_Z1_EldoradoAndMtnPass	75	75	75
Eldorado 500kV	SCADSNV_Z5_SCADSNV	149	149	149
Red Bluff	SCADSNV_Z4_RiversideAndPalmSprings	0	278	0
Colorado River	SCADSNV_Z4_RiversideAndPalmSprings	0	278	0
Crazy Eyes	SCADSNV_Z2_GLW_VEA	125	100	100
Mesa 115 kV*	SPGE-Carrizo	50	50	50
Lamont 115*	SPGE-Kern	95	95	95
Kettleman*	SPGE_Z1_Westlands	10	10	10
Gold Hill	NorCalOutsideTxConstraintZones	59	59	59
Martin	NorCalOutsideTxConstraintZones	250	250	250
Walnut	TehachapiOutsideTxConstraintZones	200	200	200
Hinson	TehachapiOutsideTxConstraintZones	200	200	200
Etiwanda	KramerInyoOutsideTxConstraintZones	101	101	101
Laguna Bell	TehachapiOutsideTxConstraintZones	500	500	500
Walnut	TehachapiOutsideTxConstraintZones	200	200	200
Silvergate	GreaterImpOutsideTxConstraintZones	200	200	200
Moorpark	TehachapiOutsideTxConstraintZones	500	500	500
Escondido	GreaterImpOutsideTxConstraintZones	50	50	50
Sycamore Canyon	GreaterImpOutsideTxConstraintZones	300	300	300

[59] ftp://ftp.cpuc.ca.gov/energy/modeling/Battery_Mapping_Dashboard_All_Portfolios_Final.xlsx

Talega 138kV	GreaterImpOutsideTxConstraintZones	200	200	200
Trabuco 138kV	GreaterImpOutsideTxConstraintZones	250	250	250
Encina 138kV	GreaterImpOutsideTxConstraintZones	160	160	160
Kearny	GreaterImpOutsideTxConstraintZones	10	10	10
	Total	**9,368**	**9,447**	**7,604**

* In coordination with the CPUC, adjustments were made to the final mapping of co-located solar-battery resources to accommodate the need for 155 MW of battery storage at Mesa, Lamont and Kettleman identified in the 2020-2021 transmission plan. Accordingly, 155 MW of co-located storage, along with 161 MW of solar, was moved from Gates 500 kV to Mesa, Lamont and Kettleman substations.

The CPUC has provided the following additional guidance in the Modeling Assumptions for the 2021-2022 Transmission Planning Process Report.

- Due to the uncertainty of the transmission implication of the injection point of the 1062 MW OOS wind resource in the base portfolio, it will be studied with Palo Verde and Eldorado as alternative injection points in the policy driven assessment
- The CAISO should consult with CPUC before moving forward with any new policy-driven transmission needs associated specifically with storage mapping in this planning cycle
- CPUC staff would expect to coordinate with CAISO to enable small adjustments in the CPUC's mapping of storage resources to allow for the inclusion of storage resources that are identified as mitigation for transmission issues in CAISO's 2020-2021 TPP
- Regarding the OSW Portfolio, the expected product would include the cost of upgrading transmission to accommodate the 8.3 GW OSW in the portfolio with the potential to increase to up to 21.1 GW
- The CAISO is to conduct an outlook assessment for 21.2 GW of OSW to ensure potential transmission development for early offshore wind resources is "least regrets"

3.4 Coordination with Phase II of 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

In approximately June of 2021 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 Phase II 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 Planning 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.

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 2021-2022 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 2030 greenhouse gas (GHG) reduction target, at least cost, while maintaining electric service reliability and meeting other State goals.

The CPUC has issued a Decision[60] recommending transmittal of a base portfolio along with two sensitivity portfolios for use in the 2021-2022 TPP. The base portfolio is transmitted for the purpose of being studied as part of the reliability, policy-driven and economic assessments. See Section 3 for details regarding the portfolio.

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 2030 anchor dataset (ADS) PCM as the staring database[61], 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 2031 (the 10th planning year) through production simulation, and for year 2026 (the 5th 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.

[60] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M366/K426/366426300.PDF

[61] The 2030 ADS PCM is developed in the Western Interconnection ADS process, which has a two-year cycle. The 2030 ADS PCM is the lasts product of the ADS process.

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 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 4.3-1 includes the Economic Planning Study Requests that were submitted for this planning cycle.

Table 4.3-1: Economic study requests

No.	Study Request	Submitted By	Location
1	Moss Landing – Los Aguilas 230 kV line congestion mitigation	Vistra	Northern CA
2	SWIP-North	LS Power	Idaho/Nevada
3	GLW Conversion and Upgrade Project	GridLiance West	Southern Nevada
4	Pacific Transmission Expansion Project	Western Grid Development	Northern/Southern CA

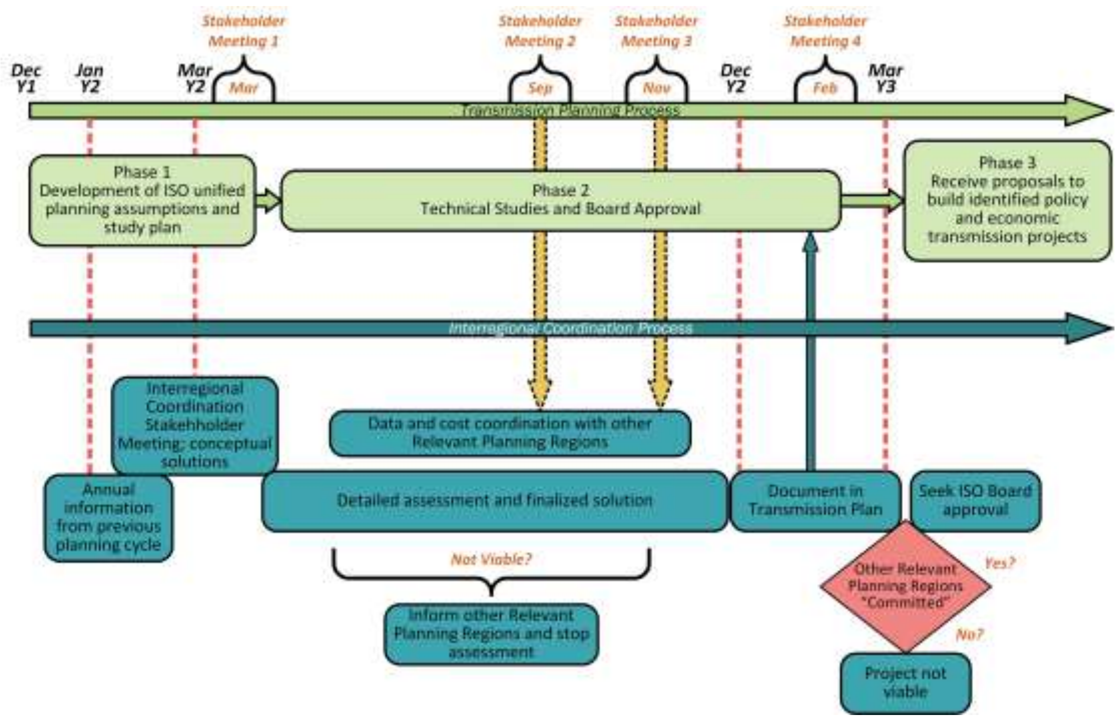
5. Interregional Coordination

During the CAISO's 2021-2022 planning cycle, the CAISO will, in coordination with the other western planning regions, will complete the odd year of the 2020-2021 interregional transmission coordination cycle and initiate the 2022-2023 interregional transmission coordination cycle, beginning on January 1, 2022. Figure 4.3-1 illustrates the interregional coordination process for the odd year of the two year cycle.

During the odd year (2021) of the interregional transmission coordination cycle the CAISO will complete the following key activities:

- Participate in a western planning regions' stakeholder meeting; and
- Based on the initial assessment of ITP in the previous year's TPP cycle, the CAISO will determine whether to further evaluate the project during the odd year of the planning cycle. The 2020-2021 TPP did not identify a need for any of the ITP's submitted to the CAISO during its open window. As such, no further consideration of the ITPs will occur during the 2021-2022 TPP.

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:

http://www.caiso.com/planning/Pages/InterregionalTransmissionCoordination/default.aspx

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:

- 2022 – Local Capacity Area Technical Study
- 2026 – 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, 2021.

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:

http://www.caiso.com/Documents/2022LocalCapacityRequirementsFinalStudyManual.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 2021-2022 CAISO Transmission Planning Process webpage.

6.1.2 Long-Term Local Capacity Requirement Assessment

Based on the alignment[62] 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 2020-2021 Transmission Plan and therefore the 2021-2022 transmission planning process will not include a 10 year out study.

6.2 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.

6.3 Frequency Response Assessment

Historically the thermal, hydro and other synchronous generators would provide sufficient frequency response to the CAISO system to be able to meet the applicable standards. Currently (as of 2/17/2021), a total of 21.23 GW of Inverter Based Resources (IBRs) (wind, solar, storage) are connected to the CAISO grid and the total installed capacity is expected to reach 33 GW by year 2031, as detailed in the Generation Assumptions section . Majority of the existing IBRs do not provide frequency response but FERC Order 842 requires that all IBRs that sign LGIA on or

[62] http://www.caiso.com/Documents/TPP-LTPP-IEPR_AlignmentDiagram.pdf

after 5/15/2018 to have frequency response capability. With high levels of IBRs connected to the CAISO system it is critical to assess the frequency response of the system in future years and identify mitigation measures if there are any issues. In addition to the transmission–connected IBRs, currently around 9.4 GW BTM PV are installed in the system and the total installed BTM PV is expected to reach around 21 GW in 2031.

The objective of this study is to assess the CAISO system frequency response in years 2026 and 2031 and identify any performance issues related to frequency response. The study case will be based on the 2026 and 2031 spring off peak cases with different assumptions on frequency response provided by the IBRs.

Study Assumptions:

- The 2026 and 2031 spring off peak cases will be used for this study. The details of the base case including the installed and dispatched IBRs, target path flows are provided in earlier section of this study plan.
- Base load flag for all generators but new IBRs in CAISO system will be set based on WECC original case. The base load flag for new IBRs in CAISO system are set based on study scenarios discussed in the next section.
- Composite load model will be used in the dynamic model which will reflect the dependency of load to frequency.
- The assumption is that DERs do not respond to frequency variations. Tripping of DER on 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 each case, the online unloaded capacity of non-IBRs in CAISO system will be set at the spinning reserve requirements under that scenario.
- The assumption is that dynamic simulations are sufficient for such assessment. Depending on the study results, a study utilizing full detail EMT models of the plants could be required to verify plant response with actual controls modelled in EMT.
- Also cases with reduced headroom on governor-responsive units will be studied. The assumptions on the headroom will be based on the study results of the base case.

Study Scenarios:

Starting with the 2026 and 2031 Spring Off Peak cases, the following scenarios with regards to generator and IBR frequency response will be studied:

- Scenario 1: Frequency response from all IBRs in CAISO system will be switched off to establish a baseline.
- Scenario 2: Frequency response will be enabled for new BESS only

- Scenario 3: Frequency response will be enabled for all new IBRs assuming 10% headroom
- Scenario 4: Starting with Scenario 1 it will be assumed that the generator headroom in WECC case is set at spinning reserve.
- Scenario 5: Starting with Scenario 4, the frequency response of individual resources that did not respond to actual frequency events in the system will be switched off.

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 total new IBR output

iii. The total output of all other CAISO generators

iv. The major path flows

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

vi. Rate of Change of Frequency (ROCOF)

6.4 Wildfire Mitigation Assessment

The CAISO as part of the 2020-2021 TPP conducted studies to assess impact of various PSPS scenarios in the PG&E area. As part of the 2021-2022 TPP the CAISO will conduct studies to assess the potential risks of de-energizing CAISO-controlled facilities in the High Fire Risk Area's (HFRA) for SCE, and SDG&E should it become necessary for PSPS events and potentially develop mitigation to alleviate impacts.

High temperatures, extreme dryness and record-high winds have created conditions in the state of California increasing the risk of major wildfires. If severe weather threatens a portion of the electric system, it may be necessary for SCE or SDG&E to turn off electricity in the interest of public safety. This practice is carried out by a Public Safety Power Shutoff or known as the PSPS events. In the SCE and SDG&E areas, multiple phases of PSPS transmission monitoring events were carried out in 2019 and 2020 potentially impacting customers in high fire risk areas across their service territories.

The assessment will begin with gathering wildfire related information. This includes collecting GIS maps for HFRA with the transmission system overlay. Such maps will be used to identify transmission facilities within the different tiers of HFRA identified by the CPUC and will be used to develop scenarios with the facilities at risk de-energized. The information gathering will also include details about HFRA previously at risk as part of prior events.

Scenario development is a critical part of the assessment. The range of scenarios selected needs to represent a reasonable set of boundary conditions and based on a fact-based framework. The scenarios also need to be feasible, for example, de-energizing all facilities within a HFRA may not be feasible for some areas. At the same time, the number of scenarios being considered also needs to be manageable within the study timeline. Combination of voltage levels, common corridors, crossings, etc will be considered in the development of scenarios.

The CAISO will work with SCE and SDG&E to prioritize HFRAs that have been prone to past PSPS or wildfire events. For these areas, SCE and SDG&E will create scenarios that remove specific CAISO-controlled facilities from service to determine the risks and performance thresholds of 1) pre-emptively de-energizing these facilities as part of a potential PSPS or 2) losing these facilities as a forced outage due to uncontrollable events such as wildfire. These scenarios may be categorized as "extreme events" if they are beyond the minimum requirements of NERC reliability standards and CAISO planning standards.

Once the scenarios are developed, the CAISO will proceed with the study with the following assessment steps to identify the potential load drop and impact on grid performance. The load drop can be divided into two different categories:

- Local or radial system load impact (direct impact) and
- Area supply or system performance impact (indirect impact)

The first step of the assessment will be to record the amount of load lost as a result of a radial system or an island created due to the facilities de-energized as part of the scenario. This is also referred to as direct impact load loss. The next step will involve assessing power flow system performance after modeling each scenario. If any pre-contingency reliability issues are identified in the power flow model, further actions will need to be taken in the form of opening the overloaded lines or further load drop to alleviate the issues. Load loss as a result these actions will be recorded as indirect impact load loss. Once the precontingency reliability issues have been addressed in the power flow model, relevant P1 contingencies will be tested to identify the need for additional mitigation actions. Load curtailment required to ensure that the power flow model is secure for the next worst P1 contingency will be included in the reporting of indirect impact load loss.

Following the assessment and based on the evaluation of direct and indirect impacts and based on the system performance following the P1 contingencies, critical facilities will be identified in each areas. The critical facilities will be such that if excluded from the scope of PSPS scenario, will have significant impact on reducing risk in terms of load loss. Once the critical facilities have been identified, the CAISO will coordinate with SCE and SDG&E to evaluate mitigation options to be able to exclude these facilities or combinations thereof from future PSPS events.

The CAISO will also look into the active CAISO approved projects in the area and see if any of the projects could potentially reduce the impact of load loss from different scenarios assessed. In case there are active projects with positive impact, the CAISO will identify those for potential opportunities to expedite the implementation. Similarly, as part of the potential mitigation, the

CAISO will also identify opportunities for minor scope change of active projects that could help reduce the load loss impact.

If none of the above approach provide reasonable benefit towards reducing load loss resulting from the PSPS scenarios assessed, the CAISO may also look into developing new upgrades. However, system performance under contingency events of PSPS is beyond the minimum requirements of NERC mandatory reliability standards and CAISO planning standards and does not require mitigation. As such, new criteria will need to be developed if new upgrades are considered for the purpose of mitigating wildfire risks.

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.

Figure 7-1: SMEs for Technical Studies in 2021-2022 Transmission Planning Process

Item/Issues	SME	Contact
Reliability Assessment in PG&E	Abhishek Singh	asingh@caiso.com
Reliability Assessment in SCE	Frank Chen	fchen@caiso.com
Reliability Assessment in SDG&E	David Le	dle@caiso.com
Reliability Assessment in VEA	Meng Zhang	mzhang@caiso.com
Policy-driven Assessment	Nebiyu Yimer	nyimer@caiso.com
Local Capacity Requirements	Catalin Micsa	cmicsa@caiso.com
Economic Planning Study	Yi Zhang	yzhang@caiso.com
Long-term Congestion Revenue Rights	Bryan Fong	bfong@caiso.com

8. Stakeholder Comments and CAISO Responses

Stakeholders are hereby requested to submit their comments to:

regionaltransmission@caiso.com

All the comments the CAISO receives from stakeholders on the 2021-2022 draft study plan and CAISO's responses will be posted to the following link:

http://www.caiso.com/planning/Pages/TransmissionPlanning/2021-2022TransmissionPlanningProcess.aspx

APPENDIX A: System Data

A1 Existing Generation

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

PTO	Existing Generation Nameplate Capacity (MW)										
	Nuclear	Natural Gas	Hydro	Solar	Wind	Biogas	Biomass	Geothermal	Battery Storage	Other	Total
PG&E	2352	13756	8394	3618	1434	113	563	1413	7	268	31938
SCE	0	14545	2756	6318	4269	156	2	343	50	952	29391
SDG&E	0	3746	46	2155	601	18	0	0	81	106	6752
VEA	0	0	0	115	0	0	0	0	0	0	115
Total	2352	32047	11195	12206	6304	306	565	1756	138	1326	68195

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 Once-through Cooled Generation

Table A2-1: Once-through cooled generation in the California ISO BAA

Generating Facility	Owner	Existing Unit/ Technology[63] (ST=Steam CCGT=Combine-Cycled Gas Turbine)	State Water Resources Control Board (SWRCB) Compliance Date	Retirement Date (If already retired or have plans to retire)	Net Qualifying Capacity (NQC) (MW)	Repowering Capacity[64] (MW) and Technology[65] (approved by the CPUC and CEC)	In-Service Date for CPUC and CEC-Approved Repowering Resources	Notes
Humboldt Bay	PG&E	1 (ST)	12/31/2010	9/30/2010	52	163 MW (10 ICs)	9/28/2010	Retired 135 MW and repowered with 10 ICs (163 MW)
		2 (ST)	12/31/2010		53			
Contra Costa	GenOn	6 (ST)	12/31/2017	April 30, 2013	337	Replaced by 760 MW Marsh Landing power plant (4 GTs)	May 1, 2013	New Marsh Landing GTs are located next to retired generating facility.
		7 (ST)	12/31/2017		337			
Pittsburg	GenOn	5 (ST)	12/31/2017	12/31/2016	312	Retired (no repowering plan)	N/A	
		6 (ST)	12/31/2017		317			
Potrero	GenOn	3 (ST)	10/1/2011	2/28/2011	206	Retired (no repowering plan)	N/A	
Moss Landing	Dynegy	1 (CCGT)	12/31/2020* (see notes at far right column)	N/A	510	The State Water Resources Control Board (SWRCB) approved mitigation plan (Track 2 implementation plan) for Moss Landing Units 1 & 2.	N/A	The State Water Resources Control Board (SWRCB) approved OTC Track 2 mitigation plan for Moss Landing Units 1 & 2.
		2 (CCGT)	12/31/2020* (see notes at far right column)	N/A	510			
		6 (ST)	12/31/2020 (see notes)	1/1/2017	754	Retired (no repowering plan)	N/A	
		7 (ST)	12/31/2020 (see notes)	1/1/2017	756	Retired (no repowering plan)	N/A	
Morro Bay	Dynegy	3 (ST)	12/31/2015	2/5/2014	325	Retired (no repowering plan)	N/A	

[63] Most of the existing OTC units, with the exception of Moss Landing Units 1 and 2, are steam generating units.

[64] The ISO, through Long-Term Procurement Process and annual Transmission Planning Process, worked with the state energy agencies and transmission owners to implement an integrated and comprehensive mitigation plan for the southern California OTC and SONGS generation retirement located in the LA Basin and San Diego areas. The comprehensive mitigation plan includes preferred resources, transmission upgrades and conventional generation.

[65] IC (Internal Combustion), GT (gas turbine), CCGT (combined cycle gas turbine)

Generating Facility	Owner	Existing Unit/ Technology[63] (ST=Steam CCGT=Combine-Cycled Gas Turbine)	State Water Resources Control Board (SWRCB) Compliance Date	Retirement Date (If already retired or have plans to retire)	Net Qualifying Capacity (NQC) (MW)	Repowering Capacity[64] (MW) and Technology[65] (approved by the CPUC and CEC)	In-Service Date for CPUC and CEC-Approved Repowering Resources	Notes
		4 (ST)	12/31/2015	2/5/2014	325	Retired (no repowering plan)	N/A	
Diablo Canyon Nuclear Power Plant	PG&E	1 (ST)	12/31/2024	11/2/2024	1122	PG&E plans to replace with renewable energy, energy efficiency and energy storage.	N/A	On June 21, 2016, PG&E has announced that it planned to retire Units 1 and 2 by 2024 and 2025, respectively. On November 30, 2020, the State Water Resources officially amended compliance schedule.[66]
		2 (ST)	12/31/2024	8/26/2025	1118			
Mandalay	GenOn	1 (ST)	12/31/2020	2/6/2018	215	Retired (no repowering)		Mandalay generating facility was retired on February 6, 2018.
		2 (ST)	12/31/2020	2/6/2018	215	SCE plans to replace with renewable energy and storage		
Ormond Beach	GenOn	1 (ST)	12/31/2020	12/31/2023	741	To be retired (no repowering)	N/A	On November 30, 2020, the SWRCB officially amended the compliance schedule.
		2 (ST)	12/31/2020	12/31/2023	775			
El Segundo	NRG	3 (ST)	12/31/2015	7/27/2013	335	560 MW El Segundo Power Redevelopment (CCGTs)	August 1, 2013	Unit 3 was retired on 7/27/2013.
		4 (ST)	12/31/2015	12/31/2015	335	Retired (no repowering)	N/A	Unit 4 was retired on December 31, 2015.
Alamitos	AES	1 (ST)	12/31/2020	1/1/2020	175	640 MW CCGT on the same property	4/1/2020	Units 1, 2 and 6 were retired on January 1, 2020 to provide emission offsets to repowering project (non-OTC units). On November 30, 2020, the SWRCB officially amended the compliance schedule for Units 3, 4 and 5.
		2 (ST)	12/31/2020	1/1/2020	175			
		3 (ST)	12/31/2020	12/31/2023	332			
		4 (ST)	12/31/2020	12/31/2023	336			
		5 (ST)	12/31/2020	12/31/2023	498			
		6 (ST)	12/31/2020	1/1/2020	495			
	AES	1 (ST)	12/31/2020	1/1/2020	226		3/1/2020	

[66] https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_policy_2020/otc2020.pdf

Generating Facility	Owner	Existing Unit/ Technology[63] (ST=Steam CCGT=Combine-Cycled Gas Turbine)	State Water Resources Control Board (SWRCB) Compliance Date	Retirement Date (If already retired or have plans to retire)	Net Qualifying Capacity (NQC) (MW)	Repowering Capacity[64] (MW) and Technology[65] (approved by the CPUC and CEC)	In-Service Date for CPUC and CEC-Approved Repowering Resources	Notes
Huntington Beach		2 (ST)	12/31/2020	12/31/2023	226	644 MW CCGT on the same property		Unit 1 was retired to provide emission offsets to repowering project (non-OTC units). On November 30, 2020, the SWRCB officially amended the compliance schedule for Unit 2.
		3 (ST)	12/31/2020	11/1/2012	227			Units 3 and 4 were retired in 2012 and converted to synchronous condensers in June 2013 to operate on an interim basis. On December 31, 2017, these two synchronous condensers were retired.
		4 (ST)	12/31/2020	11/1/2012	227			
Redondo Beach	AES	5 (ST)	12/31/2020	12/31/2021	179	To be retired	N/A	Unit 7 was retired to provide emission offsets to repowering project at Huntington Beach. On November 30, 2020, the SWRCB officially amended the compliance schedule for Units 5, 6 and 8.
		6 (ST)	12/31/2020	12/31/2021	175			
		7 (ST)	12/31/2020	10/1/2019	493			
		8 (ST)	12/31/2020	12/31/2021	496			
San Onofre Nuclear Generating Station	SCE/ SDG&E	2 (ST)	12/31/2022	June 7, 2013	1122	Retired (no repowering)	N/A	
		3 (ST)	12/31/2022		1124			
Encina	NRG	1 (ST)	12/31/2017	3/1/2017	106	500 MW (5 GTs or peakers) Carlsbad Energy Center, located on the same property as the Encina Power Plant.	New resources (Carlsbad Energy Center) achieved	OTC Unit 1 was retired on 12/31/2017. Units 2-5 were retired on 12/31/2018.
		2 (ST)	12/31/2017	12/31/2018[67]	103			
		3 (ST)	12/31/2017	12/31/2018	109			
		4 (ST)	12/31/2017	12/31/2018	299			

[67] The State Water Resources Control Board approved extending the compliance date for Encina Units 2 to 5 for one year to December 31, 2018 due to delay of Carlsbad Energy Center in-service date.

Generating Facility	Owner	Existing Unit/ Technology[63] (ST=Steam CCGT=Combine-Cycled Gas Turbine)	State Water Resources Control Board (SWRCB) Compliance Date	Retirement Date (If already retired or have plans to retire)	Net Qualifying Capacity (NQC) (MW)	Repowering Capacity[64] (MW) and Technology[65] (approved by the CPUC and CEC)	In-Service Date for CPUC and CEC-Approved Repowering Resources	Notes
		5 (ST)	12/31/2017	12/31/2018	329		commercial operation on 12/11/2018	
South Bay (707 MW)	Dynegy	1-4 (ST)	12/31/2011	12/31/2010	692	Retired (no repowering)	N/A	Retired 707 MW (CT non-OTC) – (2010-2011)

A3 Long-Term Planning Procurement Plan Resources

Table A3-1: Planned Generation

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

Table A3-2: 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[68]	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[69]	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.

[68] 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.

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

A4 Retired Generation

Table A4-1: Generation (non-OTC) projected to be retired in planning horizon[70]

PTO Area	Generating Facility	Capacity (MW)	Expected Retirement Date
None	None	None	None

[70] Table A4-1 reflects retirement of generation based upon announcements from the generators. The ISO will document generators assumed to be retired as a result of assumptions identified in Section 2.7 as a part of the base case development with the reliability results.

A5 Reactive Resources

Table A5-1: 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
Sunrise San Luis Rey	63	Shunt Capacitors
Southbay / Bay Boulevard	100	Shunt Capacitors
Mira Loma 230kV	158	Shunt Capacitors
Mira Loma 500kV	300	Shunt Capacitors
Suncrest	126	Shunt Capacitors
Penasquitos	126	Shunt Capacitors
San Luis Rey	2x225	Synchronous Condensers
Talega	2x225	Synchronous Condensers
Talega	100	STATCOM
Miguel	2x225	Synchronous Condensers
San Onofre	225	Synchronous Condensers

A6 Special Protection Schemes

Table A6-1: Existing key Special Protection Schemes in the PG&E area

PTO	Area	SPS Name
PG&E	Central Coast / Los Padres	Mesa and Santa Maria Undervoltage SPS
	Central Coast / Los Padres	Divide Undervoltage SPS
	Central Coast / Los Padres	Temblor-San Luis Obispo 115 kV Overload Scheme
	Bulk	COI RAS
	Bulk	Colusa SPS

PTO	Area	SPS Name
	Bulk	Diablo Canyon SPS
	Bulk	Gates 500/230 kV Bank #11 SPS
	Bulk	Midway 500/230 kV Transformer Overload SPS
	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 SPS
	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 SPS Scheme
	Greater Fresno Area	Ashlan SPS
	Greater Fresno Area	Atwater SPS
	Greater Fresno Area	Gates Bank 11 SPS
	Greater Fresno Area	Helms HTT RAS
	Greater Fresno Area	Helms RAS
	Greater Fresno Area	Henrietta RAS
	Greater Fresno Area	Herndon-Bullard SPS
	Greater Fresno Area	Kerckhoff 2 RAS
	Greater Fresno Area	Reedley SPS
	Greater Bay Area	Metcalf SPS
	Greater Bay Area	SF RAS
	Greater Bay Area	South of San Mateo SPS
	Greater Bay Area	Metcalf-Monta Vista 230kV OL SPS
	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 SPS
	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 SPS
	Greater Bay Area	Transbay Cable Run Back Scheme
	Humboldt	Humboldt – Trinity 115kV Thermal Overload Scheme
	North Valley	Caribou Generation 230 kV SPS Scheme #1
	North Valley	Caribou Generation 230 kV SPS Scheme #2

PTO	Area	SPS Name
	North Valley	Cascade Thermal Overload Scheme
	North Valley	Hatchet Ridge Thermal Overload Scheme
	North Valley	Coleman Thermal Overload Scheme

Table A6-2: Existing key Special Protection Schemes in SCE area

PTO	Area	SPS 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 A6-3: Existing key Special Protection Schemes in the SDG&E

PTO	Area	SPS Name
SDG&E	SDG&E	TL695A at Talega SPS
	SDG&E	TL682/TL685 SPS
	SDG&E	TL633 At Rancho Carmel SPS
	SDG&E	TL687 at Borrego SPS
	SDG&E	TL13816 SPS
	SDG&E	TL13835 SPS
	SDG&E	Border TL649 Overload SPS
	SDG&E	Crestwood TL626 at DE SPS for Kumeyaay Wind Generation
	SDG&E	Crestwood TL629 at CN SPS for Kumeyaay Wind Generation
	SDG&E	Crestwood TL629 at DE SPS for Kumeyaay Wind Generation
	SDG&E	230kV TL 23040 Otay Mesa – Tijuana SPS (currently disabled and will not be enabled until its need is reevaluated with CENACE)
	SDG&E	230kV Otay Mesa Energy Center Generation SPS
	SDG&E	ML (Miguel) Bank 80/81 Overload SPS
	SDG&E	CFE SPS to protect lines from La Rosita to Tijuana
	SDG&E	TL 50001 IV Generator Drop SPS
	SDG&E	TL 50003 IV Generator Drop SPS
	SDG&E	TL 50004 IV Generator Drop SPS
	SDG&E	TL 50005 IV Generator Drop SPS
	SDG&E	TL 50001 IV Generator SPS
	SDG&E	Imperial Valley BK80 RAS
	SDG&E	TL23040 IV 500 kV N-1 RAS
	SDG&E	TL 23054 / TL23055 RAS
	SDG&E	Path 44 South of SONGS Safety Net