California ISO

2022-2023 Transmission Planning Process Unified Planning Assumptions And Study Plan

June 30, 2022

Final

Revision 1

Foreword to Revision 1 of the Final 2022-2023 Transmission Planning Process Unified Planning Assumptions and Study Plan

On June 30, 2022 the final interregional transmission project evaluation plan was posted on the ISO's public website. The 2022-2023 Transmission Planning Process Unified Planning Assumptions and Study Plan was revised to include these evaluation plans as included in Appendix B.

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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 2022-2023 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 2021 IEPR adopted by the CEC on January 26, 2022[1].

[1] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report/2021-1

1.1 Overview of 2022-2023 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 2022-2023 transmission planning process is provided in Table 1.1-1. Should this schedule change or other aspects of the 2022-2023 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 2022-2023 planning cycle

Phase	No	Due Date	2022-2023 Activity
Phase 1	1	January 14, 2022	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 14, 2022	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 11, 2022	PTO's, neighboring balancing authorities and regional/sub-regional planning groups provide CAISO the information requested No.1 above.
	4	February 11, 2022	Stakeholders provide CAISO the information requested No.2 above.
	5	February 18, 2022	The CAISO develops the draft Study Plan and posts it on its website
	6	February 28, 2022	The CAISO hosts public stakeholder meeting #1 to discuss the contents in the Study Plan with stakeholders
	7	February 28- March 14, 2022	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, 2022	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 15, 2022	The CAISO posts preliminary reliability study results and mitigation solutions
	10	August 15, 2022	Request Window opens
	11	August 29, 2022	The CAISO will post base scenario base cases for each planning area used in the reliability assessment
	12	September 14, 2022	PTO's submit reliability projects to the CAISO
	13	September 27-28, 2022	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, 2022	Comment period for stakeholders to submit comments on the public stakeholder meeting #2 material[2]

[2] 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.

Phase	No	Due Date	2022-2023 Activity
	15	October 14, 2022	Request Window closes
	16	October 28, 2022	The CAISO post final reliability study results
	17	November 14, 2022	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 17, 2022	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 17 – December 5, 2022	Comment period for stakeholders to submit comments on the public stakeholder meeting #3 material
	20	December 14 – 15, 2022	The CAISO Board of Governors meeting provides opportunity for stakeholder comments directly to Board of Governors.
	21	January 31, 2023	The CAISO posts the draft Transmission Plan on the public website
	22	February 2023	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 2023	The CAISO finalizes the Transmission Plan and presents it to the CAISO Board of Governors for approval
	25	End of March, 2023	The CAISO posts the Final Board-approved Transmission Plan on its site
Phase 3	26[3]	April 1, 2023	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:

- IID provided the most up-to-date outage and RAS files.
- LS Power provided information about Series compensated 500kV line from Harry Allen to Eldorado, long lead time equipment outages in their system and excepted facility outage.
- Hetch Hetchy Water & Power provided topology change-files for years 2022-2023 and 2024-2032 and other optional epcls. HHWP also provided information about potential facility outage.
- TANC indicated that reliability planning data (important for the reliability planning assessments as required by the NERC TPL-001-5) is already available through WECC and that TANC does not have any additional reliability planning data for the CAISO to consider in the 2022-2023 Transmission Planning Process. However, TANC provided comments related to automatic system operation, contingencies, spare equipment availability and other planning information requested in the CAISO letter.
- Trans Bay Cable provided contingency list for the 2022-2023 TPP process.
- SVP provided load & network topology change files for multiple years for the 2022-2023 TPP process.
- SunZia Southwest Transmission Project provided information about the SunZia project.
- WAPA provided network topology change files for multiple years for the 2022-2023 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 2022-2023 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://mpp.caiso.com/Pages/Default.aspx. In order to gain access to this secured website, each individual must have a Non-Disclosure Agreement (NDA) executed with the CAISO.

The procedures governing access to different classes of protected information is set forth in Section 9.2 of the Transmission Planning BPM (BPM). As indicated in that section, access to specified information depends on whether a requesting entity meets certain criteria set forth in the CAISO tariff. The NDA application and instructions are available on the CAISO website at 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 2.1-2.15. 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 2022-2023 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 2022-2032 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 previous TPP cycle, the CAISO will evaluate areas known to have no major changes compared to assumptions made in prior planning cycles for potential use of past studies.

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

[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] (2023-2027) and longer-term[10] (2028-2032) 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 2024, 2027 and 2032. 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, LLC (GLW) owns 230kV facilities in VEA's service territory. VEA operates and maintains GLW's 230kV facilities. In this report, VEA normally refers to VEA's service territory. When identifying specific projects or specific PTOs, VEA or GLW will be used depending upon who owns the facilities specified or the PTO referenced.

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 2021-2022 or earlier CAISO transmission plans. Currently, the CAISO anticipates the 2021-2022 transmission plan will be presented to the CAISO board of governors for approval in March 2022. 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 2021 California Energy Demand (CED) Forecast 2021-2035 adopted by the California Energy Commission (CEC) on January 26, 2022[13] using the corresponding LSE and BA Table Mid Baseline spreadsheet with applicable Additional Achievable Energy Efficiency (AAEE) and Additional Achievable Fuel Substitution (AAFS). The 2021 CED Forecast also includes 8760-hourly demand forecasts for the three major Investor Owned Utility (IOU) TAC areas as well as for the entire CAISO.

The CAISO engaged in collaborative discussion with CEC and CPUC on how to consistently account for reduced energy demand from energy efficiency in the planning and procurement processes. To that end, the 2021 IEPR final report, adopted on January 26, 2022 based on the IEPR report and in consultation with the CPUC and the CAISO, recommends using the Mid Demand-AAEE Scenario 3-AAFS Scenario 3 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, AAEE and AAFS at specific locations and estimating their daily load-shape impacts, using the Mid Demand-AAEE Scenario 2-AAFS Scenario 4 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=21-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 and mid plus AAFS 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 and mid AAFS savings load forecast will be used for system studies

The 1-in-2 weather year, mid demand baseline with mid AAEE and mid AAFS 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://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report/2021-1

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.

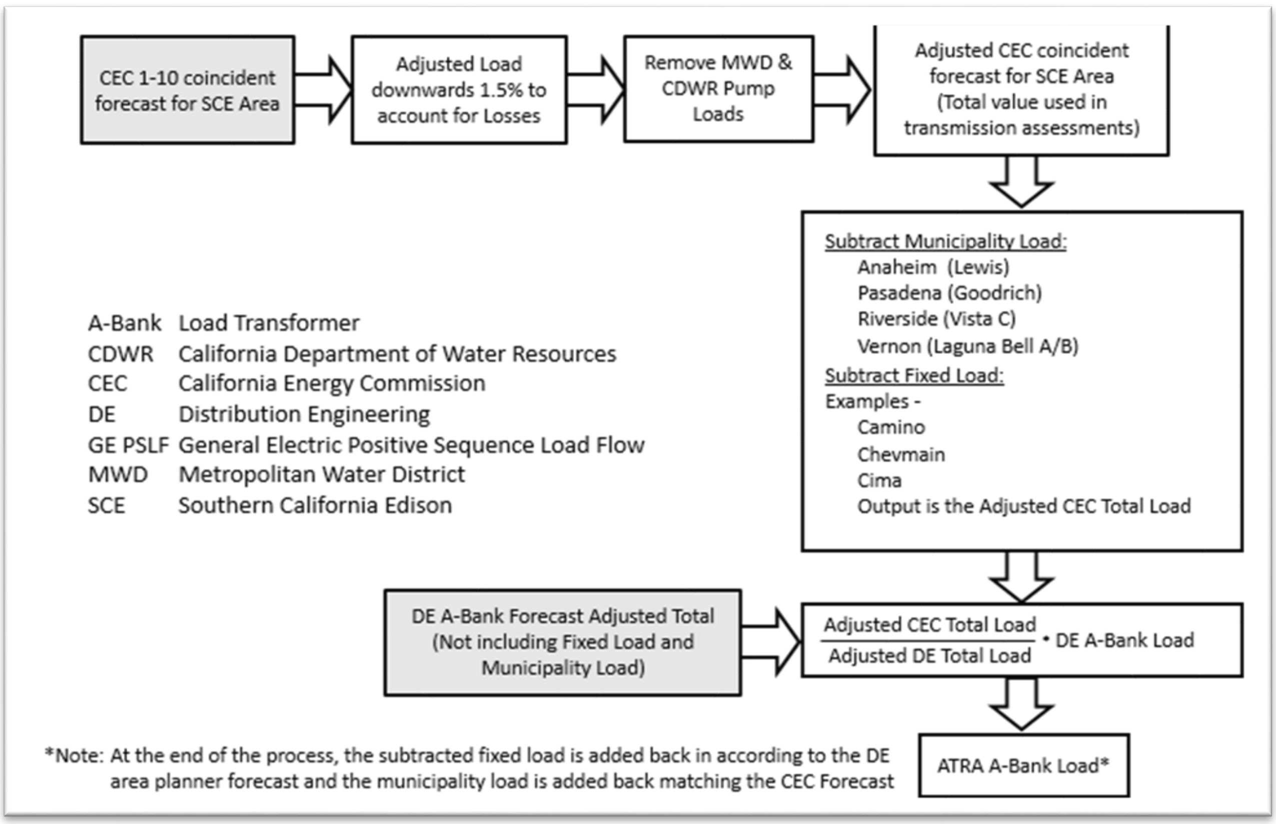
Behind-the-meter PV (BTM-PV)

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 adverse (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 2021 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 base cases (2 year and 5 year out). For the long term base case (10 year out), the average historical power factor for each planning area is used.

In the SDG&E area, power factors at all substations will be modeled based on the actual peak load data recorded in the EMS system for the year 2024 study case. For the subsequent study years a power factor of 0.995 will be used.

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

2.6.4 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 behind-the-meter PV (BTM-PV) capacity is projected to reach 24,537 MW in the mid demand case by 2032. In 2022-2023 TPP base cases, BTM-PV generation production will be modeled explicitly. The CEDU 2021-2035 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 2,950 MW in the mid demand case by 2032. Behind-the-meter storage will not be modeled explicitly in 2022-2023 TPP base cases due to lack of locational information and limitation within the GE PSLF tool to model more than one distributed resources behind each load. However it will be accounted for by netting to the load.

BTM-PV installed capacity for mid demand scenario by PTO and forecasting climate zones are shown in Table 2.6-1: . Output of the BTM-PV will be selected based on the time of day of the study using the end-use load and PV shapes for the day selected.

Behind-the-meter storage installed capacity for mid demand scenario by PTO and forecasting climate zones is shown in

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			
2022	Res	19	22	68	20	4	8	**141**	2	11	17	45	13	**88**	**50**	**279**
	Non-Res	17	42	49	17	4	41	**170**	19	8	22	124	43	**216**	**57**	**443**
2023	Res	24	28	87	26	5	10	**180**	2	13	21	56	16	**108**	**61**	**349**
	Non-Res	24	56	70	24	6	54	**234**	23	11	28	155	53	**270**	**71**	**575**

2024	**Res**	29	34	108	32	7	13	**223**	3	16	25	67	19	**130**	**72**	**425**
	Non-Res	30	69	90	30	7	66	**292**	28	15	34	186	63	**326**	**86**	**704**
2025	**Res**	35	41	129	38	8	15	**266**	3	19	30	80	23	**155**	**84**	**505**
	Non-Res	37	83	111	36	9	79	**355**	32	18	41	217	73	**381**	**100**	**836**
2026	**Res**	42	48	153	45	9	18	**315**	4	23	35	93	26	**181**	**97**	**593**
	Non-Res	43	97	132	53	10	92	**427**	36	22	47	249	83	**437**	**115**	**979**
2027	**Res**	48	56	177	52	11	21	**365**	4	26	39	107	30	**206**	**109**	**680**
	Non-Res	50	111	153	49	12	104	**479**	40	25	54	281	93	**493**	**129**	**1101**
2028	**Res**	55	64	202	60	12	24	**417**	5	29	54	121	34	**243**	**122**	**782**
	Non-Res	57	125	174	56	13	117	**542**	44	29	60	313	104	**550**	**144**	**1236**
2029	**Res**	63	72	229	67	14	27	**472**	5	33	50	136	38	**262**	**136**	**870**
	Non-Res	63	139	195	62	15	130	**604**	48	33	66	345	114	**606**	**158**	**1368**
2030	**Res**	70	81	256	75	16	30	**528**	6	37	56	152	43	**294**	**149**	**971**
	Non-Res	70	153	216	69	16	143	**667**	52	36	73	378	124	**663**	**173**	**1503**
2031	**Res**	78	90	284	83	17	33	**585**	6	41	62	168	47	**324**	**163**	**1072**
	Non-Res	77	167	237	75	18	156	**730**	56	40	79	410	134	**719**	**188**	**1637**
2032	**Res**	85	99	312	92	19	36	**643**	7	45	68	184	52	**356**	**176**	**1175**
	Non-Res	84	181	259	82	19	169	**794**	60	44	86	443	145	**778**	**203**	**1775**

Table 2.6-2. These resources will be netted to load in the 2022-2023 TPP base cases.

A forecasting climate zone map provided by CEC is included below in Figure 2.6-2, which can be used in allocating BTM-PV to various areas for bus level forecasting.

Table 2.6-1: Mid demand baseline PV self-generation installed capacity by PTO[14]

PTO	Forecast Climate Zone	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
PGE	Central Coast	538	600	655	713	772	833	893	953	1012	1071	1129
	Central Valley	1646	1816	1963	2115	2271	2432	2593	2755	2916	3075	3230
	Greater Bay Area	1730	1913	2070	2238	2415	2602	2793	2988	3185	3383	3578
	North Coast	471	519	560	604	648	692	737	780	823	865	906
	North Valley	337	368	395	424	454	485	516	548	579	609	639
	Southern Valley	2116	2289	2446	2608	2774	2941	3106	3270	3431	3588	3739
	PG&E Total	**6838**	**7505**	**8089**	**8702**	**9334**	**9985**	**10638**	**11294**	**11946**	**12591**	**13221**
SCE	Big Creek East	489	527	562	597	634	670	706	742	778	816	853
	Big Creek West	264	291	314	339	365	392	420	449	479	510	542
	Eastern	1044	1122	1187	1254	1319	1386	1453	1523	1594	1666	1739
	LA Metro	1606	1765	1899	2046	2202	2637	2539	2719	2908	3104	3308
	Northeast	780	862	931	1006	1086	1170	1260	1354	1452	1555	1660
	SCE Total	**4183**	**4567**	**4893**	**5242**	**5606**	**6255**	**6378**	**6787**	**7211**	**7651**	**8102**
SDGE	SDGE	**1762**	**1915**	**2043**	**2180**	**2322**	**2468**	**2616**	**2764**	**2913**	**3062**	**3210**
CAISO Total		**12783**	**13987**	**15025**	**16124**	**17262**	**18708**	**19632**	**20845**	**22070**	**23304**	**24533**

[14] 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[15]

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			
2022	Res	19	22	68	20	4	8	**141**	2	11	17	45	13	**88**	**50**	**279**
	Non-Res	17	42	49	17	4	41	**170**	19	8	22	124	43	**216**	**57**	**443**
2023	Res	24	28	87	26	5	10	**180**	2	13	21	56	16	**108**	**61**	**349**
	Non-Res	24	56	70	24	6	54	**234**	23	11	28	155	53	**270**	**71**	**575**
2024	Res	29	34	108	32	7	13	**223**	3	16	25	67	19	**130**	**72**	**425**
	Non-Res	30	69	90	30	7	66	**292**	28	15	34	186	63	**326**	**86**	**704**
2025	Res	35	41	129	38	8	15	**266**	3	19	30	80	23	**155**	**84**	**505**
	Non-Res	37	83	111	36	9	79	**355**	32	18	41	217	73	**381**	**100**	**836**
2026	Res	42	48	153	45	9	18	**315**	4	23	35	93	26	**181**	**97**	**593**
	Non-Res	43	97	132	53	10	92	**427**	36	22	47	249	83	**437**	**115**	**979**
2027	Res	48	56	177	52	11	21	**365**	4	26	39	107	30	**206**	**109**	**680**
	Non-Res	50	111	153	49	12	104	**479**	40	25	54	281	93	**493**	**129**	**1101**
2028	Res	55	64	202	60	12	24	**417**	5	29	54	121	34	**243**	**122**	**782**
	Non-Res	57	125	174	56	13	117	**542**	44	29	60	313	104	**550**	**144**	**1236**
2029	Res	63	72	229	67	14	27	**472**	5	33	50	136	38	**262**	**136**	**870**
	Non-Res	63	139	195	62	15	130	**604**	48	33	66	345	114	**606**	**158**	**1368**
2030	Res	70	81	256	75	16	30	**528**	6	37	56	152	43	**294**	**149**	**971**
	Non-Res	70	153	216	69	16	143	**667**	52	36	73	378	124	**663**	**173**	**1503**
2031	Res	78	90	284	83	17	33	**585**	6	41	62	168	47	**324**	**163**	**1072**
	Non-Res	77	167	237	75	18	156	**730**	56	40	79	410	134	**719**	**188**	**1637**
2032	Res	85	99	312	92	19	36	**643**	7	45	68	184	52	**356**	**176**	**1175**
	Non-Res	84	181	259	82	19	169	**794**	60	44	86	443	145	**778**	**203**	**1775**

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

Figure 2.6-2: CEC forecasting climate zone map

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 one or more 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 2032 base cases.

The CPUC has issued a Decision[16] recommending transmittal of a base portfolio along with a sensitivity portfolio for use in the 2022-2023 TPP. The base portfolio is designed to meet the 38 MMT GHG emissions target by 2030 and is based on the 2020 IEPR Demand and High EV Penetration. The portfolios are developed using the RESOLVE resource optimization model. The base portfolio is comprised of new and future baseline resources, which have recently been contracted for or come online and the additional generic resources that are selected to achieve policy and reliability targets. The CAISO will model only the new baseline resources in the near term 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 2022.

The base portfolio is comprised of wind, solar, geothermal, pumped hydro, biomass and battery storage resources. 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 2022-2023 TPP.

Table 2.7-1: New Resource Buildout of the base portfolio

Resource Type	Total (MW)
Biomass	134
Distributed Solar	125
Geothermal	1,159
In-State Wind	3,032
LDES, PSH	1,000
Li_Battery	13,564
Offshore Wind	1,708
OOS Wind on Exiting Out-of-State Transmission	610
OOS Wind on New Out-of-State Transmission	1,500
Solar	17,379
Retirements	(1,055)
Grand Total	**39,156**

16 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M449/K173/449173804.PDF

shows the new resource buildout of the base portfolio.

Table 2.7-1: New Resource Buildout of the base portfolio[17][18]

Resource Type	Total (MW)
Biomass	134
Distributed Solar	125
Geothermal	1,159
In-State Wind	3,032
LDES, PSH	1,000
Li_Battery	13,564
Offshore Wind	1,708
OOS Wind on Exiting Out-of-State Transmission	610
OOS Wind on New Out-of-State Transmission	1,500
Solar	17,379
Retirements	(1,055)[19]
Grand Total	**39,156**

2.7.3 Thermal generation

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

2.7.4 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,

[17] The base portfolio also includes 441 MW of shed demand response for which bus-bar mapping is not available

[18] The base portfolio amounts are comprised of new and future baseline resources, which have recently been contracted for or come online and the additional generic resources that are selected to achieve policy and reliability targets.

[19] These retirements were assumed by the CPUC as an input into the RESOLVE capacity expansion model and are not an output of the RESOLVE analysis.

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 2.7.6.

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

Other Retirements – The CPUC has assumed a 40-year age-based retirement of thermal generators (CHP and Peakers) in developing the 2022-2023 TPP base portfolio. Based on this assumption, 1055 MW of nameplate capacity of CHP and Peaker units were assumed to be retired. The CPUC has transmitted a list of the units that are affected by the age-based retirement assumption[20]. Accordingly, the ISO will model units on the list as retired in the 2032 base cases.

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.

[20] https://files.cpuc.ca.gov/energy/modeling/Thermal%20Age%20Based%20Retirements%20Assumptions_V2021_10_15.xlsx

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 2.7-2 below outlines modeling assumptions for distribution connected resources in the TPP base cases.

Table 2.7-2: Modeling assumptions of distribution connected resources

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

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).

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.

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

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

[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

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 2022-2023 IRP, 13,571 MW of storage was provided in the base portfolio as listed in Table 2.7-1and will be modeled in the year 2032 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 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.

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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

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)	181	System-wide SubLAP RDRR	30 minutes
Capacity Bidding Program (CBP)	40	System-wide SubLAP PDR	Day Ahead
Peak Day Pricing (PDP)	8.8	System-wide	Day Ahead
SmartRate™	3.9	System-wide	Day Ahead
SmartAC™	11.8	System-wide SubLAP Selected 21 Substations PDR	None required
DRAM	NA		>30 Minutes
Total	245.5		

SCE

Load Impact Report, 1-in-2 weather year condition portfolio-adjusted August 2022 ex-ante DR impacts at CAISO peak			
Supply-side DR (MW)	**MW**	**Market Model/Level of Dispatch**	**Response time**
Base Interruptible Program 15 Minute (BIP-15)	176	RDRR- System-wide, Sublap, A-Bank	20 Minutes or Less
Base Interruptible Program 30 Minute (BIP-30)	336	RDRR- System-wide, Sublap, A-Bank	30 Minutes
Agricultural and Pumping Interruptible (API)	38	RDRR- A-bank	20 Minutes or Less
Summer Discount Plan Residential (SDP-R)	166	PDR-A-bank	20 Minutes or Less
Summer Discount Plan Commercial (SDP-C)	17	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 (CBP)	5	PDR- System-wide, Sublap	CBP Day-Ahead = Day Ahead CBP Day-Of = 60 minutes
Demand Response Auction Mechanism (DRAM) Pilot	98	PDR- System-wide, Sublap	Various

Total	874		

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)	0.80	System-wide SubLAP RDRR	20 minutes
Capacity Bidding Program (CBP)	1.70	System-wide SubLAP PDR	>30 Minutes
Critical Peak Pricing (CPP)[29]	1.99	System-wide PDR	>30 Minutes
AC Saver – Day Ahead	6.95	System-wide PDR	>30 Minutes
AC Saver – Day Of	2.11	System-wide PDR	>30 Minutes
DRAM (demonstrated capacity)	12.77	System-wide PDR	>30 Minutes
Total	26.32		

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	1.091	1.068	1.082

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

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

2.8.3 Energy Storage

The CAISO models the existing, under construction and/or approved procurement status energy storage projects in the reliability base cases. For the purpose of this table, co-located resources have their own respective market IDs as compared to hybrid resources that have a single market ID. The CAISO 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		
			2024	2027	2032
PG&E	Transmission(Stand alone and co-located)	980	1248	1248	1248
	Front of the meter Distribution including co-located	6.5	20	20	20
	Behind the meter Customer (Residential and Non-Residential)	313	517	845	1439
	Hybrid Generation [31]	0	136	136	2232
SCE	Transmission(Stand alone and co-located)	1522	2818	2818	2818
	Front of the meter Distribution including co-located	70	145	145	145
	Behind the meter Customer (Residential and Non-Residential)	303	456	699	1135
	Hybrid Generation	1771	2964	2964	10249
SDG&E	Transmission(Stand alone and co-located)	384	674	674	674
	Front of the meter Distribution including co-located	60.5	30	30	30
	Behind the meter Customer (Residential and Non-Residential)	178.3	158	238	379
	Hybrid Generation	0	0	0	0
Total		**4608**	**9166**	**9817**	**20369**

As part of the 2022-2023 IRP, 13,571 MW of storage was provided in the base portfolio as listed in Table 2.7-1 and will be modeled in the year 2032 base cases. 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.

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

31 Hybrid Generation for all PTO's assumption is based on CPUC base portfolio list

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[32].

Table 2.9-1: Major Path flows in northern area (PG&E system) assessment[33]

Path	Transfer Capability/SOL (MW)	Scenario in which Path will be stressed
Path 26 (N-S)	4,000[34]	Summer Peak
PDCI (N-S)	3,210[35]	
Path 66 (N-S)	4,800[36]	
Path 15 (N-S)	-5,400[37]	Spring Off Peak
Path 26 (N-S)	-3,000	
PDCI (N-S)	-975[38]	
Path 66 (N-S)	-3,675	Winter Peak

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

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

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

33 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)

34 May not be achievable under certain system loading conditions.

35 Current operational limit is 3210 MW.36 The Path 66 flows will be modeled to the applicable seasonal nomogram for the base case relative to the northern California hydro dispatch.

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

37 May not be achievable under certain system loading conditions

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

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

Path	Transfer Capability/SOL (MW)	Target Flows (MW)	Scenario in which Path will be stressed, if applicable
Path 26 (N-S)	4,000	4,000	Summer Peak
Path 26 (S-N)	3,000	0 to 3,000	Spring Off Peak
PDCI (N-S)	3,210[39]	3,210	Summer Peak
PDCI (S-N)	975[40]	975	Spring Off Peak
West of River (WOR) (E-W)	12,150	0 to 11,200	Summer Peak
East of River (EOR) (E-W)	10,100	1,400 to 10,100	Summer Peak
East of River (EOR) (W-E)		2,000 to 7,500	Summer Peak/Spring Off peak
San Diego Import	2,765~3,565	2,400 to 3,500	Summer Peak
Path 45 (N-S)	600	0 to 600	Summer Peak
Path 45 (S-N)	800	0 to 300	Spring Off Peak

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/market/Pages/TransmissionOperations/Default.aspx for the list of publicly available Operating Procedures.

[39] WECC Existing Path rating is 3200MW, Current operational limit is 3210 MW.

[40] WECC Existing Path rating is 3100MW, Current operational limit is 975 MW.

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 2.7.

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 2.9 to assess their FAC-013-2 Transfer Capability or FAC-014-2 System Operating Limits (SOL) for the planning horizon, as applicable.

The base scenarios for the reliability analysis are provided in Table 2.11-1.

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

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2024	2027	2032
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		
		2024	2027	2032	2024	2027	2032	2024	2027	2032	2024	2027	2032	2024	2027	2032
PG&E	Summer Peak	7/25 HE 19	See CAISO	See CAISO	5%	See CAISO	See CAISO	2%	See CAISO	See CAISO	56%	See CAISO	See CAISO	100%	See CAISO	See CAISO
PG&E	Spring Off Peak	4/24 HE 20	See CAISO	See CAISO	0%	See CAISO	See CAISO	0%	See CAISO	See CAISO	49%	See CAISO	See CAISO	70%	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	12/09 HE 19	12/14 HE 19	12/9 HE 19	0%	0%	0%	0%	0%	0%	15%	13%	13%	74%	76%	78%
SCE	Summer Peak	9/3 HE 16	9/7 HE 17	9/7 HE 19	47%	24%	0%	51%	21%	0%	15%	19%	40%	100%	100%	100%
SCE	Spring Off Peak	4/24 HE 20	See CAISO	See CAISO	0%	See CAISO	See CAISO	0%	See CAISO	See CAISO	46%	See CAISO	See CAISO	66%	See CAISO	See CAISO
SDG&E	Summer Peak	9/4 HE 19	9/2 HE 19	9/4 HE 19	0%	0%	0%	1%	0%	0%	25%	33%	33%	100%	100%	100%
SDG&E	Spring Off Peak	5/28 HE 20	See CAISO	See CAISO	0%	See CAISO	N/A	0%	See CAISO	N/A	61%	See CAISO	N/A	74%	See CAISO	N/A
VEA	Summer Peak	9/3 HE 16	9/7 HE 17	9/7 HE 19	N/A	N/A	N/A	37%	14%	0%	N/A	N/A	N/A	100%	100%	100%
VEA	Spring Off Peak	4/24 HE 20	See CAISO	See CAISO	N/A	N/A	N/A	0%	See CAISO	See CAISO	N/A	N/A	N/A	66%	See CAISO	See CAISO

PTO	Scenario	Day/Time	BTM-PV			Transmission Connected PV [41]			Transmission Connected Wind			% of non-coincident PTO managed peak load		
			PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE
CAISO	2032 Summer Peak	9/7 HE 19	6%	0%	0%	6%	0%	0%	32%	30%	25%	96%	100%	97%
	2032 Spring Off Peak[42]	4/4 HE 13	79%	80%	85%	92%	94%	95%	22%	31%	28%	12%	22%	3%
	2027 Summer Peak	9/7 HE 19	6%	0%	0%	6%	0%	0%	32%	40%	25%	95%	99%	97%
	2027 Spring Off Peak	4/4 HE 13	79%	79%	86%	92%	94%	95%	22%	31%	28%	20%	27%	12%

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

[41] The transmission connected PV in the 2032 Spring Off Peak case might be curtailed down to limit the export within acceptable range.

[42] All energy storage resources will be modeled in charging mode in this case.

2.11.3 Sensitivity Studies

In addition to the base scenario studies that the CAISO will be assessing in the reliability analysis for the 2022-2023 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
	2024	2027	2032
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 or different import level or storage charging	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 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	2024 Summer Peak	5%	99%	2%	99%	56%	62%	Solar and wind dispatch increased to 20% exceedance values
	Off peak with heavy renewable output or different import level or storage charging	2024 Spring Off-peak	0%	0%	0%	0%	20%	20%	Different import levels on COI and P26.
	Summer Peak with high CEC forecasted load	2027 Summer Peak	6%	6%	0%	0%	32%	32%	Load increased by turning off AAEE
SCE	Summer Peak with heavy renewable output and minimum gas generation commitment	2024 Summer Peak	46%	91%	51%	99%	19%	67%	Solar and wind dispatch increased to 20% exceedance values
	Off peak with heavy renewable output or different import level or storage charging	2024 Spring Off-peak	0%	0%	0%	0%	48%	48%	Storage Charging in load pockets.
	Summer Peak with high CEC forecasted load	2027 Summer Peak	0%	0%	0%	0%	40%	40%	Load increased per CEC high load scenario
SDG&E	Summer Peak with heavy renewable output and minimum gas generation commitment	2024 Summer Peak	0%	96%	0%	96%	33%	51%	Solar and wind dispatches increased to 20% exceedance values
	Off peak with heavy renewable output or different import level or storage charging	2024 Spring Off-peak	0%	0%	0%	0%	68%	68%	Storage Charging in load pockets.
	Summer Peak with high CEC forecasted load	2027 Summer Peak	0%	0%	0%	0%	25%	25%	Load increased per CEC high load scenario
VEA	Summer Peak with forecasted load addition	2024 Summer Peak			51%	51%			Load increase reflect future load service request
	Off-peak with heavy renewable output	2027 Spring Off-peak			0%	96%			Modeled active GIDAP projects in the queue
	Summer Peak with forecasted load addition	2027 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[43]. 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)[44] 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
2024	Summer Peak	2025 Heavy Summer 3	10/29/2021
	Winter Peak	2022-23 Heavy Winter 3	1/7/2022
	Spring Off-Peak	2022 Heavy Spring 1	3/5/2021
2027	Summer Peak	2027 Heavy Summer 2	3/29/2021
	Winter Peak	2026-27 Heavy Winter 2	3/31/2021
	Spring Off-Peak	2024 Light Spring 1	5/1/2020
2032	Summer Peak	2032 Heavy Summer 1	8/13/2021
	Spring Off-Peak	2033 Light Spring 1	12/6/2021

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 2032 summer peak base case

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

[44] 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.

for the northern California will use 32HS1a1 base case from WECC as the starting point. However, the network representation in northern California will be updated with the latest information provided by the PTO followed by some adjustments on load level or generation dispatch to ensure the case represents the assumptions described in this document. This practice will result in better accuracy of network representation both inside and outside the study area.

2.13 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 2.1.3, TPL-001-5 categories P0, P1 and P3 contingencies will be evaluated. These contingencies lists will be made available on the CAISO secured website.

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

Loss of one generator (P1.1)[45][46]
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)[47]
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)

Multiple contingency (Category P5)

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

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[48] (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.

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

2.13.1 Known Outages and Outage scheduling Assessment

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

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

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

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

Any issues or conflicts identified with planned outages in the assessment described above will be documented in the IRO-017 Requirement R4[49] Planned Outage Mitigation Plan in addition to the transmission plan.

Table 2.13-1 provides the known or potential outages involving multiple facilities that can cause outage scheduling challenges that are selected for assessment in the current transmission planning cycle based on information obtained from TOs and TOPs. Single element outages are

[49] 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.

not listed in the table unless they are scheduled to be performed during the summer peak season because, as mentioned above, they are assessed using the results of category P1 to P7 contingency studies.

Table 2.13-1: Known outages involving multiple facilities selected for assessment[50]

PTO Area	Scheduled Outage Involving Multiple Facilities	Facilities Affected	Additional Description, If Needed
PGAE	None		
SCE	Lugo 500 kV bus outage	East or West 500 kV Bus	
SCE	MWD Pump outage	MWD pump load	high voltage concern
SCE	Barre 220 kV bus	East or West 220 kV Bus	risk of SCE's 220 kV system seperation.
SCE/LADWP	Sylmar 220 kV bus	Sylmar 220 kV bus section #1 or	Next P1 event casues system separation between SCE and LADWP at Sylmar
SDG&E	Jamacha - 69kV & 12kV Rebuild	JAM - TL643 69kV North Bus Outage	To be evaluated for the 2024 off-peak load condition
SDG&E	TL666 / TL662 Reliability Project	TL666 and TL662 69kV lines	To be evaluated for the 2027 summer peak load condition
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.

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

2.13.2 Category P5 Assessment of Single Points Protection System Failure

TPL-001-5.1 requires the CAISO to include failure of non-redundant components of a Protection System identified in Table 1 Category P5 Footnote 13 items a, b, c, and d as shown below in its annual assessment.

Table 2.13-1: Excerpt from TPL-001-5 Table 1 for Category P5

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes

Footnote 13

For purposes of this standard, non-redundant components of a Protection System to consider are as follows:

> *a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;*
>
> *b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center);*
>
> *c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit);*
>
> *d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).*

<u>Implementation</u>

The CAISO has started coordinating with Transmission Owners in its Planning Coordinator Area and their protection engineers to obtain the necessary data to identify the single points of failure in their protection systems that will be used to develop the steady state and stability contingency list. In order to include the single points of failure analysis at the latest in the 2022-2023 Transmission Planning Process (TPP), the Transmission Owners needs to provide the following necessary data no later than May 1, 2022:

a. Identifying the scope of protection systems' exposure to single points of failure, and

b. Developing steady state and stability for P5 contingency lists.

It is noted that the Corrective Action Plans (CAPs) required to meet Requirement R2, Part 2.7 associated with the non-redundant components of a Protection System identified in Table 1 Category P5 Footnote 13, items a, b, c, and d, will need to be developed by July 1, 2025, which is 24 months after the effective date of the standard.

2.13.3 New Stability Analysis Requirement for Loss of Long Lead Time Equipment

TPL-001-5.1 added stability analysis, in addition to steady state analysis (Requirement R2.1.5), to assess unavailability of major transmission equipment with a lead time of one year or more as set out in Requirement R2.4.5. The requirement stipulates the analysis shall be performed for the selected P1 and P2 category events identified in TPL-001-5.1 Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

Implementation Plan

The CAISO has sent to each Transmission Planner (TP) in its area the updated Roles and Responsibilities Matrix and accompanying Letter Agreement for TPL-001-5.1 between each TP and the CAISO, as the PC, to assign the responsibility for performing the assessment required under R2.1.5 and R2.4.5 to each TP. In general, the TP will provide its own spare equipment strategy to the CAISO.

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[51] 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)[52]. 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

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

[52] 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.

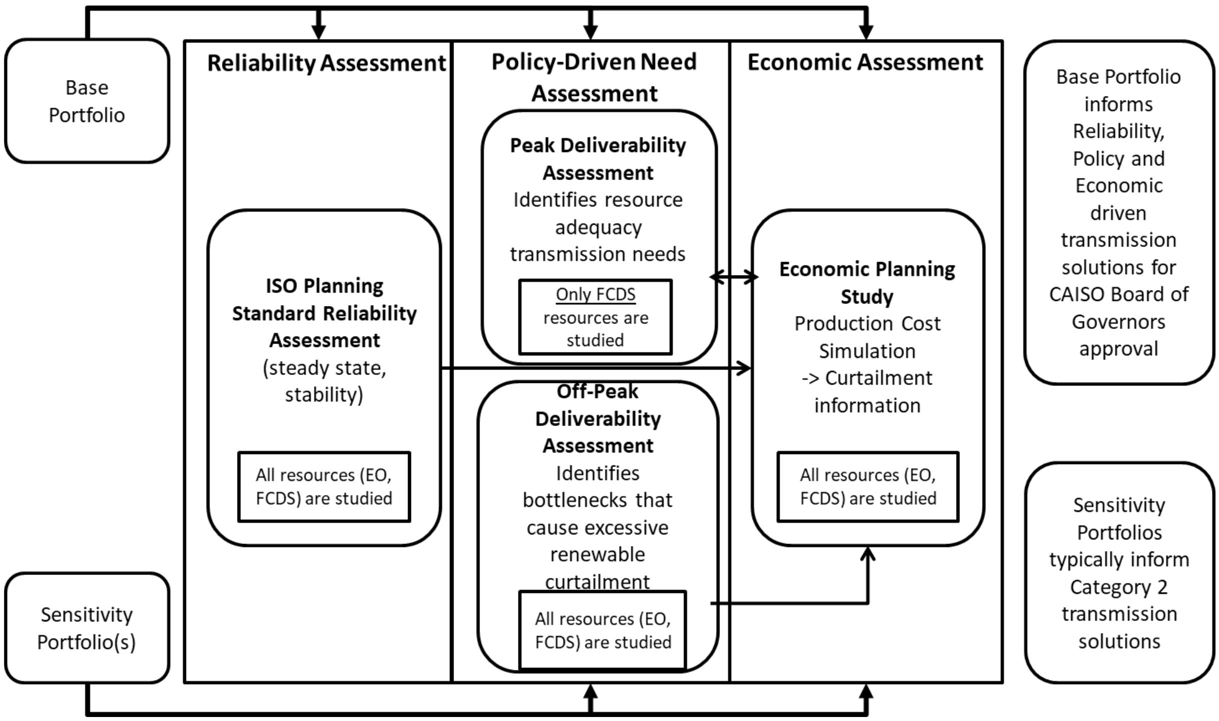
Evaluation of the need for policy-driven transmission elements begins in Phase 1 with the CAISO's specification, in the context of the unified planning assumptions and study plan, of the public policy objectives it proposes to adopt for transmission planning purposes in the current cycle. For the 2022-2023 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 to ensure portfolio resources selected with full capacity deliverability status (FCDS) are deliverable and can count towards meeting resource adequacy needs. The assessment examines whether sufficient transmission capability exists to transfer generation from a given sub-area to the aggregate of CAISO control area load when the generation is needed most. The CAISO performs the assessment in accordance with the on-peak deliverability assessment methodology[53].

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.[54]

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

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

Production cost model simulation (PCM) study

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

3.3 Resource portfolios 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[55] recommending transmittal of a base portfolio along with a sensitivity portfolio for use in the 2022-2023 TPP. The decision is accompanied by a document entitled Modeling Assumptions for the 2022-2023 Transmission Planning Process which describes the methodology and results of the busbar mapping process and includes guidance for TPP studies[56].

CPUC staff develop the portfolios using the RESOLVE capacity expansion model. The portfolio is comprised of new and future baseline resources, which have recently been contracted for or come online and the additional generic resources that are selected to achieve policy and reliability targets. The CAISO will model the new 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 2022.

The base portfolio is a Preferred System Plan (PSP) portfolio designed to meet the 38 MMT GHG emissions target by 2030. The portfolio was developed based on the 2020 IEPR demand forecast utilizing the high electric vehicle assumptions. The portfolio is comprised of solar, geothermal, pumped hydro, biomass, battery storage and wind resources including some out-of-state and offshore wind resources. The portfolio data provided includes:

- The resource portfolio selected to meet the GHG and reliability targets complete with bus-bar mapping and transmission limit calculations[57]
- Baseline resource assumptions[58],
- Age-based retirement assumptions[59]

A sensitivity portfolio based on a 30 MMT GHG target with the IEPR high electrification demand scenario will also be developed by the CPUC, CEC and CAISO and studied in this transmission plan. CPUC staff currently anticipate to transmit the sensitivity portfolio by June 1, 2022. The ISO

[55] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M449/K173/449173804.PDF

[56] https://files.cpuc.ca.gov/energy/modeling/Modeling_Assumptions_2022-2023_TPP_V.2022-2-7.pdf

[57] https://files.cpuc.ca.gov/energy/modeling/BusbarMapping_Dashboard_38MMT_V2022_02_08_v2.xlsx

[58] https://files.cpuc.ca.gov/energy/modeling/workbook:Baseline_Reconciliation_V2022_02_08.xlsx

[59] https://files.cpuc.ca.gov/energy/modeling/Thermal%20Age%20Based%20Retirements%20Assumptions_V2021_10_15.xlsx

currently intends to structure the study of the sensitivity potfolio as a special study as described in section 6.6 in order to document the reliability, deliverability and production cost analysis results in one place. Despite the proposed treatment of the sensitivity portfolio assessment as a special study for the reasons mentioned above, the results of the sensitivity study will be used the same way as any policy driven sensitivity study in accordance with the ISO Tariff.

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. Table 3.3-1 shows the composition of the base portfolio by resource type.

Table 3.3-1: Composition of the base portfolio[60,61]

Resource Type	Total (MW)	FCDS (MW)
Biomass	134	134
Distributed Solar	125	125
Geothermal	1,159	1,159
In-State Wind	3,032	2,533
LDES, PSH	1,000	1,000
Li_Battery	13,564	13,564
Offshore Wind	1,708	1,588
OOS Wind on Exiting Out-of-State Transmission	610	610
OOS Wind on New Out-of-State Transmission	1,500	1,500
Solar	17,379	5,490
Retirements[62]	(1,055)	(1,055)
Grand Total	**39,156**	**26,647**

Table 3.3-2 provides a summary of base portfolio resources by location.

60 The base portfolio also includes 441 MW of shed demand response and 432 MW of new baseline resources for which bus-bar mapping is not available

61 The base portfolio amounts shown are comprised of new and future baseline resources, which have recently been contracted for or come online and the additional generic resources that are selected to achieve policy and reliability targets.

62 These retirements were assumed by the CPUC as an input into the RESOLVE capacity expansion model and are not an output of the RESOLVE analysis.

Table 3.3-2: Base portfolio resources by location[63]

RESOLVE Resource Name	Resource Type	Total (MW)	FCDS (MW)	EODS (MW)
InState Biomass	Biomass/Biogas	134	134	
Solano_Geothermal	Geothermal	79	79	
Inyokern_North_Kramer_Geothermal	Geothermal	40	40	
Southern_Nevada_Geothermal	Geothermal	440	440	
Greater_Imperial_Geothermal	Geothermal	600	600	
Distributed Solar	Solar	125	125	
Greater_LA_Solar	Solar	1,503		1,503
Southern_PGAE_Solar	Solar	2,803	1,022	1,781
Tehachapi_Solar	Solar	4,753	1,751	3,002
Greater_Kramer_Solar	Solar	1,456	385	1,071
Southern_NV_Eldorado_Solar	Solar	2,716	770	1,946
Riverside_Solar	Solar	1,968	862	1,106
Arizona_Solar	Solar	1,881	600	1,281
Imperial_Solar	Solar	300	100	200
Northern_California_Wind	Wind	656	305	351
Solano_Wind	Wind	420	272	148
Kern_Greater_Carrizo_Wind	Wind	60	60	
Carrizo_Wind	Wind	287	287	
Central_Valley_North_Los_Banos_Wind	Wind	186	186	
Tehachapi_Wind	Wind	275	275	
Southern_Nevada_Wind	Wind	442	442	
Wyoming_Wind/Idaho_Wind	OOS Wind, New Tx	1,062	1,062	
Riverside_Palm_Springs_Wind	Wind	106	106	
New_Mexico_Wind	OOS Wind, New Tx	438	438	
SW_Ext_Tx_Wind	OOS Wind, Ext Tx	610	610	
Baja_California_Wind	Wind	600	600	
Humboldt_Bay_Offshore_Wind	Offshore Wind	120		120
Morro_Bay_Offshore_Wind	Offshore Wind	1,588	1,588	
Total Non-Storage		**25,647**	**13,139**	**12,509**
Greater_LA_Li_Battery	Li_Battery	2,861	2,861	
Northern_California_Li_Battery	Li_Battery	607	607	
Southern_PGAE_Li_Battery	Li_Battery	1,624	1,624	
Tehachapi_Li_Battery	Li_Battery	3,051	3,051	
Greater_Kramer_Li_Battery	Li_Battery	869	869	
Southern_NV_Eldorado_Li_Battery	Li_Battery	1,236	1,236	
Riverside_Li_Battery	Li_Battery	1,608	1,608	
Arizona_Li_Battery	Li_Battery	759	759	
Imperial_Li_Battery	Li_Battery	50	50	
San_Diego_Li_Battery	Li_Battery	899	899	
Total Battery		**13,564**	**13,564**	**-**
Tehachapi_LDES	LDES	500	500	
San_Diego_Pumped_Storage	LDES	500	500	

63 The base portfolio amounts shown are comprised of new and future baseline resources, which have recently been contracted for or come online and the additional generic resources that are selected to achieve policy and reliability targets.

Total LDES		**1,000**	**1,000**	**-**
Grand Total		**40,211**	**27,702**	**12,509**

3.4 Deliverability assessment methodology

3.4.1 On-peak deliverability assessment

On-peak deliverability assessment is performed under two distinct system conditions – the highest system need (HSN) scenario and the secondary system need (SSN) scenario. The HSN scenario represents the period when the capacity shortage is most likely to occur. In this scenario, the system reaches peak sale with low solar output. The highest system need hours represent the hours ending 18 to 22 in the summer months.

The secondary system need scenario represents the period when capacity shortage risk increases if variable resources are not deliverable during periods when the system depends on their high output for resource adequacy. In this scenario, the system load is modeled to represent the peak consumption level and solar output is modeled at a significantly higher output. The secondary system need hours are hours ending 15 to 17 in the summer months.

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

Transmission

The ISO will model the same transmission system as in the 2032 peak load base case that is used in the reliability assessment performed as part of the current transmission planning process.

System load

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

Maximum resource output (Pmax) assumptions

Pmax in the on-peak deliverability assessment represents the resource-type specific maximum resource output assumed in the deliverability assessment. For non-intermittent resources, the same Pmax is used in the HSN and SSN scenarios. The most recent summer peak NQC is used as Pmax for existing non-intermittent generating units. For proposed new non-intermittent generators that do not have NQC, the Pmax is set according to the interconnection request. For non-intermittent generic portfolio resources, the FCDS capacity provided in the portfolio is used as the Pmax. For energy storage resources, the Pmax is set to the 4-hour discharging capacity, limited by the requested maximum output from the resource, if applicable. For hybrid projects, the study amount for each technology is first calculated separately. Then the total study amount among all technologies is based on the sum of each technology, but limited by the requested maximum output of the generation project.

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

The maximum resource output (Pmax) assumptions used in HSN and SSN deliverability assessment are shown in Table 3.4-1

Table 3.4-1: Maximum resource output tested in the deliverability assessment

Area	HSN			SSN		
	SDG&E	SCE	PG&E	SDG&E	SCE	PG&E
Solar	3.0%	10.6%	10.0%	40.2%	42.7%	55.6%
Wind	33.7%	55.7%	66.5%	11.2%	20.8%	16.3%
New Mexico Wind	67%			35%		
Wyoming Wind	67%			35%		
Diablo OSW	100%			37%		
Morro Bay OSW	100%			49%		
Humboldt Bay OSW	100%			53%		
Energy Storage	100% or 4-hour equivalent if duration is < 4-hour					
Non-Intermittent resources	NQC or 100%					

Import Levels

For the HSN scenario, the net scheduled imports at all branch groups as determined in the 2022 annual Maximum Import Capability (MIC) assessment set the imports in the study. Approved MIC expansions will be added to the import levels. Historically unused Existing Transmission Contracts (ETC's) crossing control area boundaries are modeled as zero MW injections at the tie point, but available to be turned on at remaining contract amounts for screening analysis.

For the SSN scenario, the hour with the highest total net imports among all secondary system need hours from the 2022 MIC assessment data will be selected. Net scheduled imports for the hour set the imports in the study. Approved MIC expansions are added to the import levels.

Portfolio resources in the IID area and out-of-state portfolio resources delivered on new out-of-state transmission are dispatched once import levels in the base cases are set as described above.

General On-peak deliverability assessment procedure

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

Screening for Potential Deliverability Problems Using DC Power Flow Tool

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

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

or

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

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

Verifying and Refining the Analysis Using AC Power Flow Tool

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

When the 20 units with the highest impact on the facility can be increased more than 1,500 MW, the impact of the remaining amount of generation to be increased is considered using a Facility Loading Adder. The Facility Loading Adder is calculated by taking the remaining MW amount available from the 20 units with the highest impact multiplied by the DFAX of each unit. An equivalent MW amount of generation with negative DFAX is also included in the Facility Loading Adder, up to 20 units. If the net impact from the Facility Loading Adders is negative, the impact is set to zero and the flow on the analyzed facility without applying Facility Loading Adders is reported.

The ISO has its on-peak deliverability assessment simulation procedure implemented in PowerGem's Transmission Adequacy & Reliability Assessment (TARA) software. The ISO Deliverability Assessment module in TARA was used to perform the policy-driven on-peak deliverability assessment.

Mitigation Alternatives

Potential mitigation alternatives that will be considered to address on-peak deliverability constraints include but are not limited to Remedial Action Schemes (RAS), reduction of portfolio battery storage behind the constraints and transmission upgrades.

3.4.2 Off-peak deliverability assessment

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

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

The dispatch assumptions discussed above apply to both full capacity and energy-only resources. However, depending on the amount of generation in the portfolio, it may be impossible to balance load and resources under such conditions with all portfolio generation dispatched. The dispatch assumptions are applied to all existing, under-construction and contracted generators first, then some portfolio generators if needed to balance load and resources. This establishes a system-wide dispatch base case or master base case that is the starting case for developing each of the study area base cases to be used in the off-peak deliverability assessments. Table 3.4-2 summarizes the generation dispatch assumptions in the master base case.

Table 3.4-2: ISO System-Wide Generator Dispatch Assumptions

	Dispatch Level
wind	44%
solar	68%
battery storage	0
hydro	30%
thermal	15%

The off-peak deliverability assessment may be performed for each study area separately. The study areas in general are the same as the reliability assessment areas in generation interconnection studies. Below is the typical list of the study areas, which may be adjusted depending on the portfolio.

- PG&E north
- PG&E Fresno

- PG&E Kern
- SCE Northern
- SCE North of Lugo
- SCE/VEA/GWL East of Pisgah
- SCE/DCRT Eastern
- SDGE Inland
- SDGE East

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

If the renewables inside the study area are predominantly wind resources (more than 70% of total study area capacity), wind resource dispatch is increased as shown in Table 3.4-3. All the solar resources in the wind pocket are dispatched at the system-wide level of 68%. If the renewables inside the study area are not predominantly wind resources, then the dispatch assumptions in Table 3.4-4 are used. The dispatch assumptions for out-of-state and off-shore wind used in the current study are provided in Table 3.4-5.

Table 3.4-3: Local Area Solar and Wind Dispatch Assumptions in Wind Area

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

Table 3.4-4: Local Area Solar and Wind Dispatch Assumptions in Solar Area

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

Table 3.4-5: Additional Local Area Dispatch Assumptions

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

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

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

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

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

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

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

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

Mitigation Alternatives

Potential alternatives that will be considered to address off-peak deliverability constraints include, but are not limited to, Remedial Action Schemes (RAS), dispatching portfolio battery storage behind the constraints, adding new energy storage behind the constraints (subject to on-peak deliverability) and transmission upgrades. Transmission upgrades identified to address off-peak deliverability constraints will be considered as candidates for a more thorough evaluation using production cost simulation

3.5 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 2022 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 Plan Deliverability

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

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 2022-2023 transmission planning cycle.

4.1 Renewable Generation

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

The CPUC IRP base portfolio is transmitted for the purpose of being studied as part of the reliability, policy-driven, and economic assessments. See Chapter 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 2032 anchor dataset (ADS) PCM as the staring database[64], 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 2032 (the 10th planning year) through production simulation, and for year 2027 (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.

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

[64] 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.

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	SWIP North Project	LS Power	ID/NV
2	NGIV2 Project	NGIV2 and IID	AZ/CA
3	Fresno Avenal Area Congestion	PG&E	PG&E Fresno Avenal area
4	Inyokern 230 kV Upgrade	SCE	North of Lugo area
5	PTE Project	California Western Grid Development	Northern/Southern CA
6	Moss Landing – Las Aguilas 230 kV line reconductoring	Vistra	Northern CA
7	GLW 500 kV Upgrade Project	GridLiance West	Southern NV
8	GLW Geothermal Upgrade	GridLiance West	Southern NV

5. Interregional Coordination

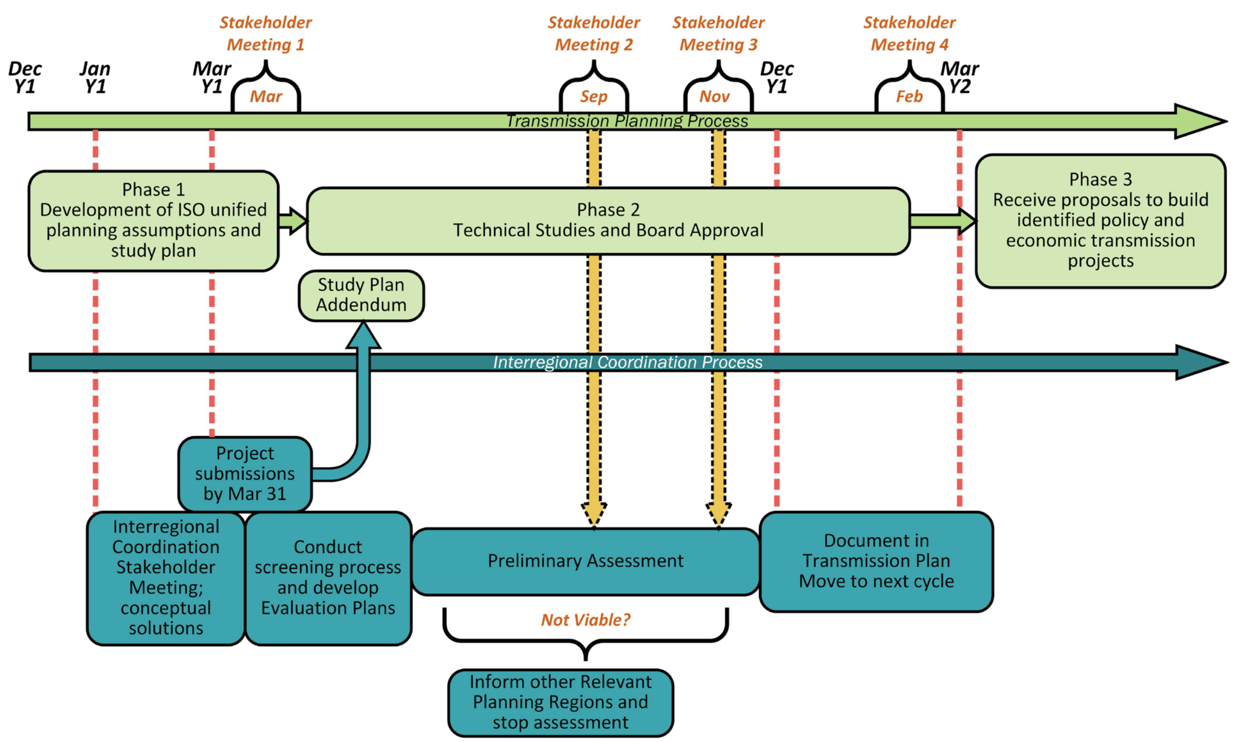
During the CAISO's 2022-2023 planning cycle, the CAISO will, in coordination with the other western planning regions, initiate the 2022-2023 interregional transmission coordination cycle. During the even year of the interregional transmission coordination cycle, the CAISO will complete the following key activities:

Host an open window (January 1 through March 31) for proposed interregional transmission projects to be submitted to the CAISO for consideration in the CAISO's 2022-2023 TPP planning cycle

Participate in a western planning regions' stakeholder meeting. The CAISO is hosting the meeting on March 4, 2022.

In coordination with other Relevant Planning Regions[65], prepare evaluation process plans for all interregional transmission projects submitted to and validated by the CAISO. Once the evaluation process plans have been finalized, they will be included in Appendix B of this study plan. Figure 4.3-1 illustrates the interregional coordination process for the even year of the two year cycle.

Figure 4.3-1 Even Year Interregional Coordination Process



65 A Relevant Planning Region means, with respect to an interregional transmission project, the western planning regions that would directly interconnect electrically with the interregional transmission project, unless and until such time as a Relevant Planning Region determines that such interregional transmission project will not meet any of its regional transmission needs, at which time it would no longer be considered a Relevant Planning Region.

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:

2023 – Local Capacity Area Technical Study
2027 – 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, 2022.

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/2023LocalCapacityRequirementsFinalStudyManual.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 2022-2023 CAISO Transmission Planning Process webpage.

6.1.2 Long-Term Local Capacity Requirement Assessment

Based on the alignment[66] 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 2022-2023 transmission planning process will include a 10 year out study.

6.2 Maximum Import Capability Expansion Requests

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

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

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

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

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

Table 4.3-1 includes the valid Maximum Import Capability expansion requests that were submitted for this planning cycle.

Table 6.2-1: Valid Maximum Import Capability expansion requests

No.	Requestor Name	Intertie Name (Scheduling Point)	MW quantity
1	San Diego Community Power	IID-SCE_ITC (MIR2)	150
2-5	Valley Ellectric Assotiation	MEAD_ITC (MEAD 230)	123

The CAISO has received 12 submittals with requests for MIC expansion. They contained 29 distinct requests (a few were duplicates – the LSE provided the request and the supplier provided a requests for the same resource).

Based on the CAISO interpretation of the Tariff and the Transmission Planning BPM (TP BPM) requirements 5 distinct requests qualify as valid requests based on the following factors:

1. LSEs with valid RA contracts not already accounted for as Pre-RA Import Commitments or New Use Import Commitment.

For the following reasons, 24 distict request do not qualify at this time:

2. Submittals by LSEs and/or resource owners with "shortlisted" contracts - since they do not have an existing RA contract with an CAISO LSE.
3. Submittals by resource owners with resources in other Balancing Authority Area (BAA) queue including site exclusivity - since they do not have an existing RA contract with an CAISO LSE.
4. Submittals by owners of Pseudo-ties or Dynamic schedules with Transmission Service Agreements (TSA) to the CAISO border – since they do not have an existing RA contract with an CAISO LSE. The TSA is required to participate in the CAISO energy market as an energy only resource (see Tariff section 40.8.1.12.1) plus the TSAs are given out on non-simultaneous bases (incompatible with the MIC calculation).
5. Submittals by transmission owners – since they do not increases any existing single interties transmission capability, they do not increase the overall CAISO transmission import capability and they do not create any new intertie transmission capability. Resources connected to these transmission requests could qualify on their own if they have an existing RA contract not already accounted for as Pre-RA import Commitments or New Use Import Commitments.

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

6.3 Long-Term Congestion Revenue Rights (LT CRR)

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

6.4 Frequency Response Assessment

Inverter Based Resources (IBR) will become an ever higher proportion of the overall energy resource mix and as per FERC Order 842 must provide frequency response for grid disturbances. The ability of IBR with frequency control enabled to response to system events with available enough operating headroom is now well-established. Despite this evidence there remain operating scenarios that warrant additional investigation with regards to frequency disturbances that will be subject in the upcoming planning cycle.

The main operating paradigm is for BESS plants to charge during daylight hours and then discharge during peak system load conditions with little to no ambient light. At the end of the discharge cycle, typically at the start of the day, the state of charge of BESS plants will be low and may not be able to adequately contribute to system disturbances. With low BESS capacity solar plants with suitable frequency control capability could be enlisted to provide any missing headroom. The latter scenario is a non-traditional use of solar plants and has not been invoked, but is plausible as IBR penetration continues.

The objective of this study is to assess the CAISO system frequency response in years 2027 and 2032 and identify performance issues related to frequency response for the selected scenarios. The study case will be based on the 2027 and 2032 spring off peak cases with different assumptions on frequency response provided by the IBRs.

Study Assumptions:

- The 2027 and 2032 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.
- 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 as much as is possible under that scenario.
- The assumption is that dynamic simulations are sufficient for such assessment. Depending on the study results, a recommendation could result requesting a special study for full detail EMT models of the plants could be required to verify plant response.

Study Scenarios:

Starting with the 2027 and 2032 Spring Off Peak cases, the following scenarios with regards to generator and IBR frequency response will be studied:

- Scenario 1: Frequency response from all new and existing IBRs in CAISO system will have frequency control switched off to establish a baseline.
- Scenario 2: Maximize use of solar plant headroom when Battery Energy Storage Systems (BESS) are at the start of their charging cycle. Input with regards to actual operation will be obtained to best simulate BESS behavior under low state of charge during a system event.
- Scenario 3: maximize existing and new BESS with capable control so that they run with an adequate amount of headroom output during end-of-day peak load conditions with a pre-existing single element outage. The pre-contingency equipment outage has yet to be determined but will be representative of system operating experience and maintenance. The level of headroom will be determined as per the new base cases and BESS availability.
- Scenario 4: Starting with Scenario 2 it will be assumed that the generator headroom in CAISO areas will be set at spinning reserve.
- Scenario 5: Starting with Scenario 3 it will be assumed that the generator headroom in CAISO areas will be set at spinning reserve.

Study Methodology and Monitored Parameters:

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

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

ii. The existing and new IBR output

iii. The total output of all other CAISO generators

iv. The major path flows

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

vi. Rate of Change of Frequency (ROCOF)

7. Special Studies

7.1 Transmission Reliability Study for the LA Basin and San Diego-Imperial Valley Local Capacity Areas with Reduced Reliance on Aliso Canyon Gas Storage

The Aliso Canyon Natural Gas Storage Facility (Aliso Canyon), located in the Santa Susana Mountains of Los Angeles County, is the largest natural gas storage facility in California. The gas storage facility provides gas support to the core and non-core customers, including electric generation located in the LA Basin between the CAISO and the Los Angeles Department of Water and Power (LADWP) Balancing Authority Areas. On October 23, 2015, Southern California Gas Company (SoCalGas) crews discovered a leak at the natural gas storage well at Aliso Canyon. The leak was stopped and the well was sealed in February 2016. Subsequently, the California Public Utility Commission (CPUC)[67] has capped the inventory level at Aliso Canyon at various levels, and most recently, at 41.16 Bcf[68] in November 2021.

In the 2022-2023 transmission planning cycle, the CAISO will undertake a transmission study to evaluate the potential reliability impacts to the transmission facilities in the LA Basin and to some extent the San Diego-Imperial Valley local capacity areas in the CAISO

[67] The CPUC has jurisdiction over the above ground infrastructure beginning where the storage facility connects to the pipeline, or “at the wellhead.” In addition, the CPUC has jurisdiction over the recovery of costs related to the storage facility as well as ensuring that Southern California Gas Company provides safe, reliable service at just and reasonable rates. The California Geologic Energy Management Division (CalGEM) has primary jurisdiction over Aliso Canyon’s underground facilities, and decided the maximum allowable operating pressure in the field to be 2,926 psi, which translates to an inventory of 68.6 billion cubic feet (Bcf) of natural gas.

[68] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M421/K086/421086399.PDF

Balancing Authority Area due to strong interaction between these two areas. The CAISO will work with the CPUC to obtain potential ranges of gas-fired generation capacity impacts, and to the extent possible, the generating units that are associated with these ranges. Additionally, the CAISO will also work with the CPUC to identify potential resource replacements for these impacted generation to the extent possible and the CAISO will also plan to evaluate potential transmission upgrades needed to maintain transmission reliability in the LA Basin and to some extent the San Diego-Imperial Valley area, as necessary, based on applicable NERC, WECC and CAISO reliability standards.

7.2 Policy Driven Assessment of the High Electrification Sensitivity Scenario

In the 2022-2023 transmission planning cycle, the CAISO will undertake a special study to evaluate the potential reliability impacts to the transmission facilities based on a high electrification scenario. The CEC, in collaboration with the CPUC and the CAISO, is developing a demand scenario that places a greater emphasis on electrification than is embedded within the CEC's 2021 IEPR energy demand forecast. The CPUC will also be developing a resource portfolio based upon the high electrification scenario. The CEC and CPUC are targeting to provide the high electrification scenario load forecast and resource portfolio to the CAISO by June 1, 2022. The CAISO will engage stakeholders when further details are available.

8 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 2022-2023 Transmission Planning Process

Item/Issues	SME	Contact
Reliability Assessment in PG&E	Preethi Rondla	prondla@caiso.com
Reliability Assessment in SCE	Frank Chen	fchen@caiso.com
Reliability Assessment in SDG&E	Rene Romo	rromodesantos@caiso.com
Reliability Assessment in VEA	Meng Zhang	mzhang@caiso.com
Reduced Dependence on Aliso Canyon Gas Storage in the LA Basin and San Diego-Imperial Valley Local Capacity Areas	David Le	dle@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

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	Geo-thermal	Battery Storage	Other	Total
PG&E	2352	15818	8290	4429	1476	103	451	1074	980	1737	36710
SCE	0	11334	2620	8050	3890	142	4	336	1765	2996	31137
SDG&E	0	3616	40	2324	701	17	0	0	520	249	7467
VEA	0	0	0	115	0	0	0	0	0	0	115
Total	2352	30768	10950	14918	6067	262	455	1410	3265	4982	75429

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[69] (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[70] (MW) and Technology[71] (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	

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

70 The CAISO, 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.

71 IC (Internal Combustion), GT (gas turbine), CCGT (combined cycle gas turbine)

Generating Facility	Owner	Existing Unit/ Technology[69] (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[70] (MW) and Technology[71] (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.[72]
		2 (ST)	12/31/2024	8/26/2025	1118			
Mandalay	GenOn	1 (ST)	12/31/2020	2/6/2018	215	Retired (no repowering) SCE plans to replace with renewable energy and storage		Mandalay generating facility was retired on February 6, 2018.
		2 (ST)	12/31/2020	2/6/2018	215			
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	

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

Generating Facility	Owner	Existing Unit/ Technology[69] (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[70] (MW) and Technology[71] (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	12/31/2023	179	To be retired	N/A	Unit 7 was retired to provide emission offsets to repowering project at Huntington Beach. On December 23, 2021, the SWRCB officially amended the compliance schedule for Units 5, 6 and 8.
		6 (ST)	12/31/2020	12/31/2023	175			
		7 (ST)	12/31/2020	10/1/2019	493			
		8 (ST)	12/31/2020	12/31/2023	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[73]	103			
		3 (ST)	12/31/2017	12/31/2018	109			
		4 (ST)	12/31/2017	12/31/2018	299			

[73] 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[69] (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[70] (MW) and Technology[71] (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[74]	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[75]	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.

[74] 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.

[75] 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[76]

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

[76] Table A4-1 reflects retirement of generation based upon announcements from the generators. The CAISO 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
	Central Coast / Los Padres	Paso Robles 70 kV Undervoltage SPS

PTO	Area	SPS Name
	Central Coast / Los Padres	Coburn Transfer trip
	Central Coast / Los Padres	Carrizo SPS
	Bulk	COI RAS
	Bulk	Colusa SPS
	Bulk	Diablo Canyon 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	FRTSPS
	Greater Fresno Area	
	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 Fresno Area	Hatchet Ridge RAS
	Greater Fresno Area	Exchequer Legrand 115kV RAS
	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

PTO	Area	SPS Name
	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
	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

APPENDIX B

2022-2023 Interregional Transmission Projects Evaluation Plans

ITP Evaluation Process Plan

North Gila-Imperial Valley #2 Transmission Project

June 15, 2022

The goal of the coordinated Interregional Transmission Project (ITP) evaluation process is to achieve consistent planning assumptions and technical data of an ITP to be used in the individual regional evaluations of an ITP. The joint evaluation of an ITP is considered to be the joint coordination of the regional planning processes that evaluate the ITP. The purpose of this document is to provide a common framework, coordinated by the Western Planning Regions, to provide basic descriptions, major assumptions, milestones, and key participants in the ITP evaluation process.

The information that follows is specific to the ITP listed in the ITP Submittal Summary below. An ITP Evaluation Process Plan will be developed for each ITP that has been properly submitted and accepted into the regional process of the Planning Region to which it was submitted.

ITP SUBMITTAL SUMMARY

Project Submitted To:	California Independent System Operator (California ISO), and WestConnect
Relevant Planning Regions[1]:	California ISO, and WestConnect
Cost Allocation Requested From:	California ISO[2]

The Relevant Planning Regions identified above developed and have agreed to the ITP Evaluation Process Plan.

ITP SUMMARY

NGIV2, LLC submitted the North Gila-Imperial Valley #2 (NGIV2) Transmission Project for consideration as an Interregional Transmission Project. NGIV2 is a proposed 500 kV AC transmission project that will

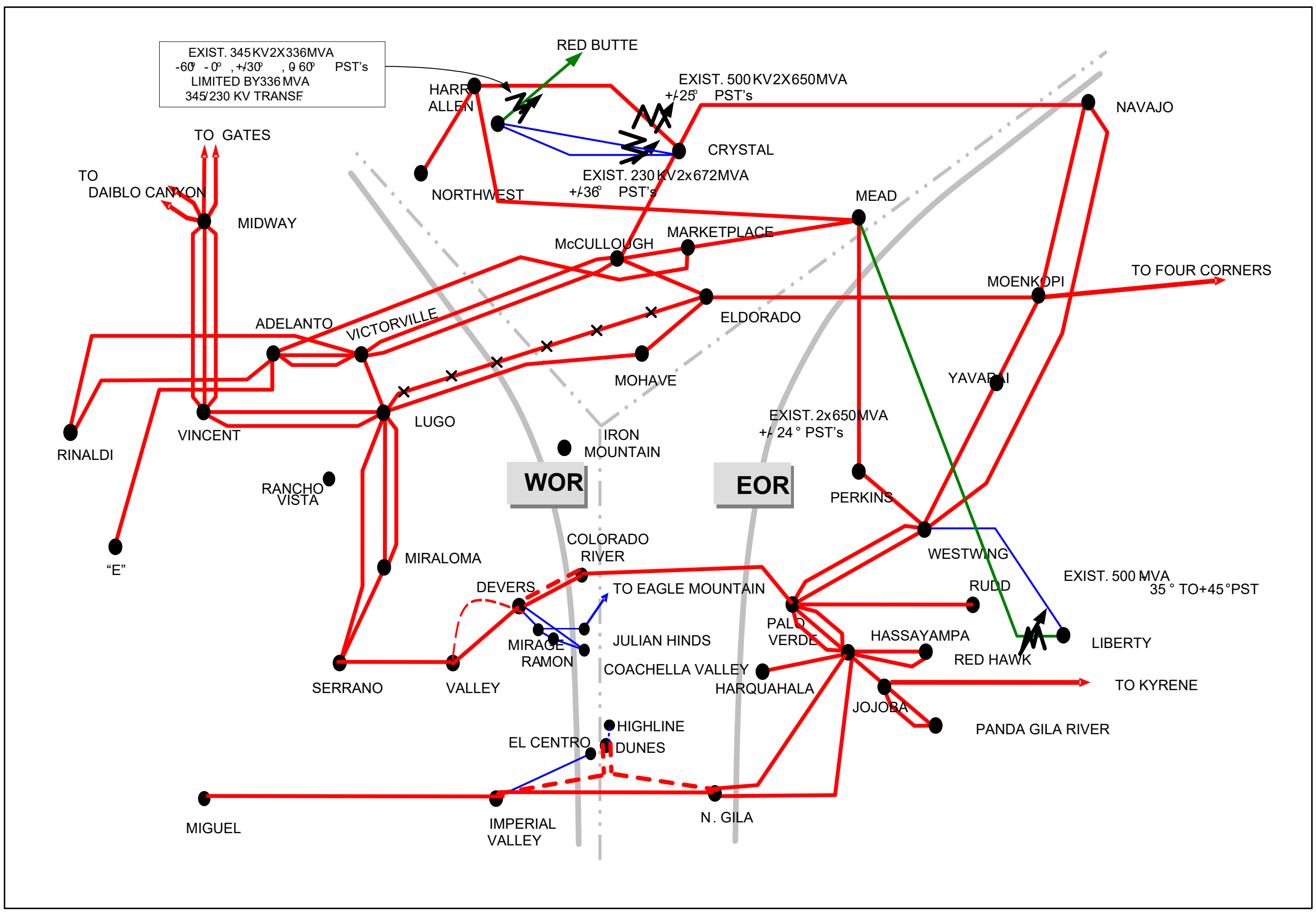
[1] With respect to an ITP, a Relevant Planning Region is a Planning Region that would directly interconnect electrically with the ITP, unless and until a Relevant Planning Region determines that the ITP will not meet any of its regional transmission needs, at which time it will no longer be considered a Relevant Planning Region.

[2] NGIV2, LLC has indicated that if IID participates in the project, they would accept a capital cost allocation of $105 million with the remainder of the costs to be recovered through the CAISO TAC. If the CAISO and IID determine there is a need for this project, the CAISO and IID would have to agree upon an appropriate cost allocation.

extend approximately 90 miles and will be constructed between southwest Arizona and southern California (see Figure 1). The line will parallel the existing North Gila-Imperial Valley line, also known as the Southwest Power Link (SWPL), and will connect the existing 500 kV North Gila substation (in the WestConnect planning region) with the existing 500 kV Imperial Valley substation (in the California ISO planning region). NGIV2 would be constructed to loop in a new 500/230 kV Dunes substation (in the WestConnect planning region) and would also include construction of a new 230 kV line from Dunes into the existing IID Highline 230 kV substation. A new 500/230 kV transformer would be installed in the Dunes substation as part of the NGIV2 project. This project will become an additional component of the West of Colorado River path (Western Electricity Coordination Council (WECC) path 46) and is expected to increase the East of Colorado River path (WECC path 49) transfer capability by 1,250 MW. Series compensation may be added to the project to balance flows on this new circuit and the existing SWPL line.

NGIV2, LLC completed the WECC 3-phase rating process on September 5, 2019. NGIV2, LLC is currently evaluating potential alternative routes and working with the responsible regulatory agencies to obtain all necessary project approvals. According to NGIV2, LLC, the project is expected to be in-service by December 2026.

Figure 1: North Gila-Imperial Valley #2
One-Line Diagram
(Source: NGIV2 WECC 2022 Annual Progress Report
February 18, 2022)



ITP EVALUATION BY RELEVANT PLANNING REGIONS

WestConnect has been identified as the Planning Region that will lead the coordination efforts with the other Relevant Planning Regions identified for the ITP. In this capacity, WestConnect will organize and facilitate interregional coordination meetings and track action items and outcomes of those meetings. For information regarding the ITP evaluation conducted within each Relevant Planning Region's planning process, please contact that Planning Region directly.

Given that the joint evaluation of an ITP is considered to be the joint coordination of the regional planning processes that evaluate the ITP, the following describes how the ITP fits into each Relevant Planning Region's process. This information is intended to serve only as a brief summary of each Relevant Planning Region's process for evaluating an ITP. Please see each Planning Region's most recent study plan and/or Business Practice Manual for more details regarding its overall regional transmission planning process.

California Independent System Operator

The final study plan for the 2022-2023 Transmission Planning Process has been posted on the CAISO website on March 31st, 2022[3]. The study plan details the load, resources, interchange levels and other modelling assumptions and methodologies for the required studies to identify any need for reliability, economic, or policy-driven transmission projects.

NGVI2, LLC also submitted the NGIV2 project into the CAISO's 2022-2023 transmission planning process as an economic study request. If selected as a high priority economic study, the CAISO will assess as an alternative the NGIV2 project to determine if there is an economic need justification. NGIV2, LLC has indicated that if IID participates in the project, and subject to the IID Board of Directors, they would accept a capital cost allocation of $105 million with the remainder of the costs to be recovered through the CAISO Transmission Access Charge (TAC). If a need is determined by the CAISO and IID for this project, the CAISO and IID would need to agree upon an appropriate cost allocation.

The power flow and production cost model datasets used in CAISO studies are posted on the CAISO's Market Participant Portal. The California ISO will coordinate its studies with WestConnect and will exchange modeling information with WestConnect commensurate with existing data confidentiality requirements.

WestConnect

WestConnect's 2022-23 Regional Study Plan was approved by its Planning Management Committee (PMC) in March of 2022.[4] The study plan describes the system assessments WestConnect will use to determine if there are any regional reliability, economic, or public policy-driven transmission needs. The models for these assessments are built and vetted during Q2 and Q3 of 2022. If regional needs are identified during Q4 of 2022, WestConnect will solicit alternatives (transmission or non-transmission alternatives (NTAs)) from WestConnect members and stakeholders to determine if they have the potential to meet the identified regional needs. If an ITP proponent desires to have their project evaluated as a solution to any identified regional need, they must re-submit their project during this solicitation

[3] http://www.caiso.com/InitiativeDocuments/FinalStudyPlan-2022-2023TransmissionPlanningProcess.pdf
[4] https://doc.westconnect.com/Documents.aspx?NID=20635&dl=1

period (Q5) and complete any outstanding submittal requirements. In late-Q5 and Q6 of the 2022-23 planning cycle, WestConnect will evaluate all properly submitted alternatives to determine whether any meet the identified regional needs, and will determine which alternative(s) provide the more efficient or cost-effective solution. The more efficient or cost-effective regional projects will be selected and identified in the WestConnect Regional Transmission Plan. Any regional or interregional alternatives that were submitted for the purposes of cost allocation and selected into the Regional Transmission Plan as the more efficient or cost-effective alternative to an identified regional need will then be evaluated for eligibility for regional cost allocation, and subsequently, for interregional cost allocation.[5]

WestConnect regional needs assessments are performed using Base Cases as identified in the Regional Study Plan. Base Cases are intended to represent "business as usual," "current trends," or the "expected future". WestConnect may also conduct information-only scenario studies that look at alternate but plausible futures. In the event regional transmission issues are observed in the assessments of the scenario studies, these issues do not constitute a "regional need", will not result in changes to the WestConnect Regional Transmission Plan, and will not result in Order 1000 regional cost allocation. The WestConnect PMC has ultimate authority to determine how to treat regional transmission issues that are identified in the information-only scenario studies. They will determine whether an issue identified in a scenario —whether it be reliability, economic, or public-policy based—constitutes additional investigation by the Planning Subcommittee.

NGIV2 Project representatives and other stakeholders are encouraged to participate in the development of the base cases to be studied in WestConnect's 2022-23 Planning Cycle. These studies, as outlined in Figure 2, will form the basis for any regional needs that ultimately may lead to ITP project evaluations in 2023. Stakeholders are also encouraged to participate in the development of the scenarios identified in WestConnect's 2022-23 Study Plan. These studies are also outlined in Figure 2.

Figure 2: WestConnect 2022-23 Transmission Assessment Summary

10-Year Base Cases (2032)	10-Year Scenarios (2032)
Heavy Summer (reliability) Light Spring (reliability) Base Case (economic)	High Clean Energy Penetration Scenario Study (reliability and economic)
May result in the identification of regional needs, requires solicitation for alternatives to satisfy needs	Informational studies that will not result in the identification of regional needs. Alternative collection and evaluation is optional and is not subject to regional cost allocation

DATA AND STUDY METHODOLOGIES

The coordinated ITP evaluation process strives for consistent planning assumptions and technical data among the Planning Regions evaluating the ITP. Below, the Relevant Planning Regions have summarized

[5] Please see the WestConnect Business Practice Manual for more information on cost allocation eligibility.

the types of studies that will be conducted that are relevant to the NGIV2 Project evaluation in each Planning Region. Methodologies for coordinating planning assumptions across the Relevant Planning Region processes are also described.

Figure 3: Relevant Planning Region Study Summary Matrix

Planning Study	California ISO	WestConnect
Economic/Production Cost Model	Using the California ISO PCM Base Case, based on the WECC 2032 Anchor Data Set (ADS), GridView will be used to perform production cost simulation. All model information will be shared with WestConnect.	Regional Economic Assessment will be performed on WestConnect 2032 Base Case PCM[6]
Reliability/Power Flow Assessment	If needed, the GE PSLF will be used to perform steady state and as needed, transient stability analysis. The WECC 2032 ADS and relevant WECC power flow cases will be modified as needed to accurately model the California network and resources that reflects the ISO's finalized 2022-2023 study plan. All model information will be shared with WestConnect.	Regional Reliability Assessment will be performed on WestConnect 2032 Heavy Summer and Light Spring cases [7]

Note that the NGIV2 Project evaluation will be conducted by each Relevant Planning Region in accordance with its approved Order 1000 Regional Planning Process. This includes study methodologies and benefits identified in planning studies.

Data Coordination

The Relevant Planning Regions will strive to coordinate major planning assumptions through the following procedures.

Economic/Production Cost Model

Each Relevant Planning Region's economic planning models will include their most recent and relevant regional planning assumptions for transmission topology and generation data. The Relevant Planning Regions also intend to use the WECC 2032 Anchor Data Set (ADS) to inform their regional economic

[6] WestConnect transmission project evaluation is subject to a number of factors, the first and most critical being the identification of regional needs as a part of the 2022-23 Base Case transmission needs assessments.
[7] Id

planning studies conducted in 2022 and 2023 (as applicable), particularly as it relates to the transmission and generation assumptions for the systems outside their Planning Region footprint. The Planning Regions will strive to coordinate any major updates made to the 2032 ADS as part of their regional model development efforts in late Q3, 2022[8].

Through this coordination of planning data and assumptions, the Relevant Regions will strive to build a consistent platform of planning assumptions for Economic/Production Cost Model evaluations of the ITP.

Reliability/Power Flow Assessment

Since each Planning Region reflects characteristics and a planning focus that is unique, different power flow models are generally needed to appropriately reflect each region's system and key assumptions. As such, each Planning Region will develop its models and data that accurately reflect their Planning Region, but will seek to coordinate this information with the other Relevant Planning Regions subject to applicable confidentiality requirements. The identification of the starting WECC power flow cases ("seed cases" for the purpose of this evaluation plan), and significant assumptions or changes a Planning Region may make to a seed base case are examples of information that will be considered by each Planning Region and coordinated with the other Planning Regions. As such, the inclusion or removal of major regional transmission projects will be coordinated through existing data coordination processes, but the season or hour of study and particular system operating conditions may vary by Planning Region based on its individual regional planning scope and study plan.

[8] This schedule is dependent on the 2032 Anchor Data Set being provided by WECC no later than the end of Q2, 2022, and the sharing of planning data or assumptions will be subject to applicable confidentiality requirements in each Planning Region.

Cost Assumptions

In order for each Relevant Planning Region to evaluate whether the NGIV2 Project is a more efficient or cost-effective alternative within their regional planning process, it is necessary to coordinate ITP cost assumptions among the Relevant Planning Regions. For planning purposes, NGIV2, LLC estimated the total project cost to be $377.0 million, with a proposed split of $105.0 million for IID (WestConnect member) and $272.0 million via a CAISO Participating Transmission Owner (PTO). The project cost of the NGIV2 Project, as provided in their ITP Submittal form, is provided below.

Figure 4: North Gila-Imperial Valley #2 Project Sponsor Cost Information[9]

Project Configuration	Cost ($)
Single circuit project cost estimate	$377.0 million (2022 $$), with a proposed split of $105 million for IID and $272.0 million for a CAISO PTO

Note that this information on cost assumptions applies to costs that will be used for planning evaluation purposes. These costs may be different than what is assumed for any relevant cost allocation procedures.

COST ALLOCATION

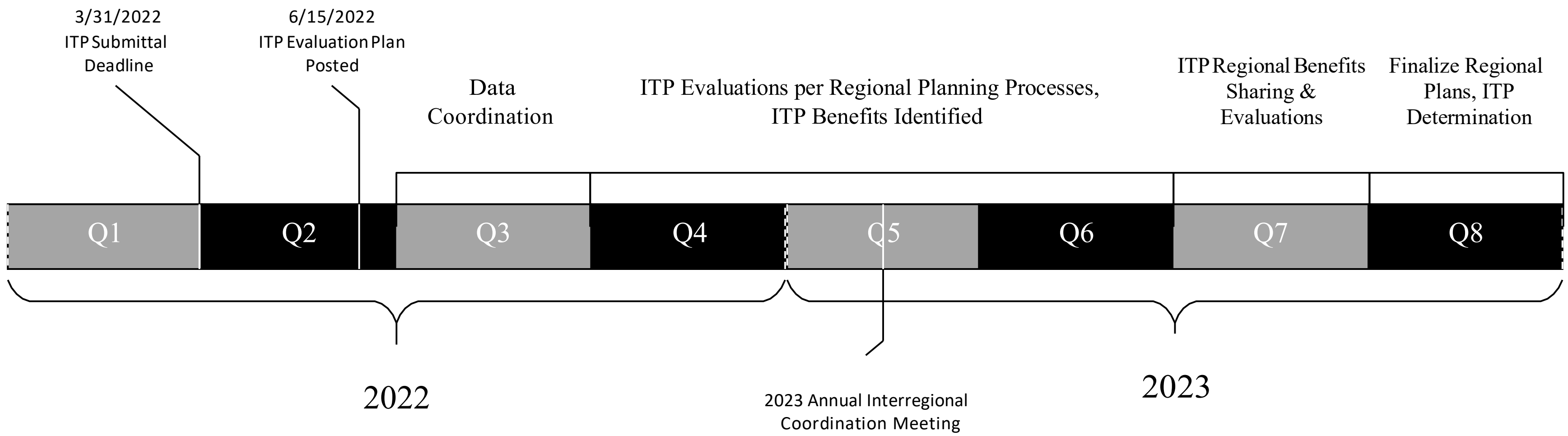
Cost allocation was not requested by the NGIV2 Project for the 2022-2023 cycle from WestConnect but it was requested from the CAISO. The project's capital costs allocated to IID (WestConnect Member) would be based on a contractual agreement made between the project participants. NGIV2, LLC has indicated that if IID participates in the project, they would accept a capital cost allocation of $105 million with the remainder of the costs to be recovered through the CAISO TAC. If the CAISO and IID determine there is a need for this project, the CAISO and IID would have to agree upon an appropriate cost allocation.

[9] This information is contingent upon verification by the Planning Regions and may be subject to change during the ITP evaluation process

SCHEDULE AND EVALUATION MILESTONES

The ITP will be evaluated in accordance with each Relevant Planning Region's regional transmission planning process during 2022 and (as applicable) 2023. The ITP Evaluation Timeline was created to identify and coordinate key milestones within each Relevant Planning Region's process. Note that in some instances, an individual Planning Region may achieve a milestone earlier than other Regions evaluating the ITP.

Figure 6: ITP Evaluation Timeline



Meetings among the Relevant Planning Regions will be coordinated and organized by the lead Planning Region per this schedule at key milestones such as during the initial phases of the ITP evaluations and during the sharing of ITP regional benefits.

CONTACT INFORMATION

For information regarding the ITP evaluation within each Relevant Planning Region's planning process, please contact that Planning Region directly.

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