2017-2018 Transmission Planning Process Unified Planning Assumptions and Study Plan

February 22, 2017

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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 ISO will adopt as the basis for identifying policy-driven transmission elements in Phase 2 of the TPP, as well as initiation of the development of a conceptual statewide transmission plan 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 ISO 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 ISO'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 ISO approval of specific transmission elements and projects identified in the 2017-2018 comprehensive transmission plan at the end of Phase 2. ISO 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 provided during the year, and has not been scheduled at this time.

The ISO has collaboratively worked with the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) to align the planning assumptions between the ISO's TPP and the CPUC's Long-term Procurement Process (LTPP), as well as the demand forecast assumptions embodied in the 2016 IEPR (approved in January 2017). With this draft study plan, the base planning assumptions for the 2017-2018 TPP are effectively aligned for the 2018-2027 planning horizon with those of the LTPP proposed to be used transmission and procurement requirements.

2. Overview of 2017-2018 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.

2.1 Stakeholder Meetings and Market Notices

During each planning cycle, the ISO 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 TPP. Additional meetings for each stage may be scheduled as needed. These meetings provide an opportunity for the ISO 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 2017-2018 transmission planning cycle is provided in Table 2-1. Should this schedule change or other aspects of the 2017-2018 transmission planning cycle require revision; the ISO will notify stakeholders through an ISO market notice which will provide stakeholders information about revisions that have been made. As such, the ISO encourages interested entities to register to receive transmission planning related market notices. To do so, go to: http://www.caiso.com/informed/Pages/Notifications/MarketNotices/MarketNoticesSubscriptionForm.aspx and submit the Market Notice Subscription Form.

Table 2-1: Schedule for the 2017-2018 planning cycle

Phase	No	Due Date	2017-2018 Activity
Phase 1	1	December 21, 2016	The ISO 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 and the ISO 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.
	2	January 21, 2017	PTO's, neighboring balancing authorities, regional/sub-regional planning groups and stakeholders provide ISO the information requested No.1 above.
	3	February 21, 2017	The ISO develops the draft Study Plan and posts it on its website
	4	February 28, 2017	The ISO hosts public stakeholder meeting #1 to discuss the contents in the Study Plan with stakeholders
	5	February 28 - March 14, 2017	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 ISO
	6	March 31, 2017	The ISO specifies a provisional list of high priority economic planning studies, finalizes the Study Plan and posts it on the public website
	7	Q1	ISO Initiates the development of the Conceptual Statewide Plan
Phase 2	8	August 15, 2017	The ISO posts preliminary reliability study results and mitigation solutions
	9	August 15, 2017	Request Window opens
	10	September 15, 2017	PTO's submit reliability projects to the ISO
	11	September/October	ISO posts the Conceptual Statewide Plan on its website and issues a market notice announcing the posting
	12	September 26-27, 2017	The ISO hosts public stakeholder meeting #2 to discuss the reliability study results, PTO's reliability projects, and the Conceptual Statewide Plan with stakeholders
	13	September 27 – October 11, 2017	Comment period for stakeholders to submit comments on the public stakeholder meeting #2 material[1]
	14	October 15, 2017	Request Window closes
	15	October/November	Stakeholders have a 20 day period to submit comments on the Conceptual Statewide Plan in the next calendar month after posting conceptual statewide plan

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

Phase	No	Due Date	2017-2018 Activity
	16	October 31, 2017	ISO post final reliability study results
	17	November 14, 2017	The ISO 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 16, 2017	The ISO 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 16 – November 30, 2017	Comment period for stakeholders to submit comments on the public stakeholder meeting #3 material
	20	December 13 – 14, 2017	The ISO to brief the Board of Governors of projects less than $50 million to be approved by ISO Executive
	21	January 31, 2018	The ISO posts the draft Transmission Plan on the public website
	22	February 2018	The ISO hosts public stakeholder meeting #4 to discuss the transmission project approval recommendations, identified transmission elements, and the content of the Transmission Plan
	23	Approximately three weeks following the public stakeholder meeting #4	Comment period for stakeholders to submit comments on the public stakeholder meeting #4 material
	24	March 2018	The ISO finalizes the Transmission Plan and presents it to the ISO Board of Governors for approval
	25	End of March, 2018	ISO posts the Final Board-approved Transmission Plan on its site
Phase 3	26[2]	April 1, 2018	If applicable, the ISO will initiate the process to solicit proposals to finance, construct, and own elements identified in the Transmission Plan eligible for competitive solicitation

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

2.2 Interregional Coordination

The ISO received FERC's final order on interregional transmission coordination on June 1, 2015. The ISO was compliant with this final order on October 1, 2015. Commensurate with its obligations, the ISO and the other western planning regions initiated their 2016-2017 interregional coordination cycle on January 1, 2016. The specific details of how the ISO will engage in interregional coordination are provided in the ISO's Transmission Planning Business Practice Manual. The ISO will keep stakeholders informed about its interregional activities through the stakeholder meetings identified in Table 2 1: Schedule for the 2017-2018 planning cycle. The interregional transmission coordination webpage is located at the following link: http://www.caiso.com/planning/Pages/InterregionalTransmissionCoordination/default.aspx.

2.3 Stakeholder Comments

The ISO 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 ISO will post these comments on the ISO Website. The ISO will target responses to comments ideally within three weeks of the close of comment periods, and no later than the next public stakeholder event relating to the Transmission Plan.

2.4 Availability of Information

The ISO website is the central place for public and non-public information. For public information, the main page for documents related to 2017-2018 transmission planning cycle is the "Transmission Planning" section located at http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx on the ISO website.

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

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 ISO tariff. The NDA application and instructions are available on the ISO website at http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx under the *Accessing transmission data* heading.

3. Conceptual Statewide Transmission Plan

With FERC's approval of the ISO's revised TPP in December 2010, the development of a conceptual statewide plan as an input for consideration in developing the ISO's comprehensive transmission plan was incorporated into phase 1 of the TPP.

Per the ISO tariff section 24.2, during Phase 1 the ISO will initiate the development of a conceptual statewide transmission plan. The plan will typically be completed during Phase 2 of the TPP, at which time it will become an input to the study process whereby the ISO evaluates the need for policy-driven transmission elements. Based on the opportunity to provide a broad geographic view of needed transmission development to meet California's 33%, and more recently, 50% renewable goals, the ISO incorporated an annual conceptual statewide transmission plan into its transmission planning process. Included in the ISO's transmission plan for the past five years, the conceptual statewide plan remains as an open framework to provide a "California centric" backdrop upon which possible collaboration with other California transmission providers could lead to development of new infrastructure to support California's renewable goals. Although the conceptual statewide plan could be useful in providing a broad geographic view of needed transmission development, the plan, as entitled, must be "conceptual" in the sense that it would be for informational purposes only and not binding on any of the California transmission providers as to which projects to approve.

4. Reliability Assessments

The ISO will analyze the need for transmission upgrades and additions in accordance with NERC Standards and WECC/ISO reliability criteria. Reliability assessments are conducted annually to ensure that performance of the system under the ISO 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 4.1.1-4.1.15. 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, reliability standards to be used to measure system performance and software or analytical tools.

4.1 Reliability Standards and Criteria

The 2017-2018 transmission plan will span a 10-year planning horizon and will be conducted to ensure the ISO-controlled grid is in compliance with the North American Electric Reliability Corporation (NERC) standards, WECC regional criteria, and ISO planning standards across the 2018-2027 planning horizon.

4.1.1 NERC Reliability Standards

The ISO 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 ISO as a registered NERC planning authority and are the primary driver of the need for reliability upgrades:[3]

- TPL-001-4: Transmission System Planning Performance Requirements[4]; and
- NUC-001-2.1 Nuclear Plant Interface Coordination.[7]

4.1.2 WECC Regional Criteria

The WECC System Performance TPL-001-WECC-CRT-3[5] Regional Criteria are applicable to the ISO as a planning authority and set forth additional requirements that must be met under a varied but specific set of operating conditions.[6]

4.1.3 California ISO Planning Standards

The California ISO Planning Standards specify the grid planning criteria to be used in the planning of ISO transmission facilities.[7] 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 ISO-controlled grid; and
- identify whether specific criteria should be adopted that are more stringent than the NERC standards or WECC regional criteria.

[3] http://www.nerc.com/page.php?cid=2%7C20
[4] 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.
[5] https://www.wecc.biz/Reliability/TPL-001-WECC-CRT-3.pdf
[6] http://compliance.wecc.biz/application/ContentPageView.aspx?ContentId=71
[7] http://www.caiso.com/Documents/FinalISOPlanningStandards-April12015_v2.pdf

4.2 Frequency of the study

The reliability assessments are performed annually as part of the ISO's TPP.

4.3 Study Horizon and Years

The studies that comply with TPL-001-4 will be conducted for both the near-term[8] (2018-2022) and longer-term[9] (2023-2027) per the requirements of the reliability standards.

Within the identified near and longer term study horizons the ISO will be conducting detailed analysis on years 2019, 2022 and 2027. If in the analysis it is determined that additional years are required to be assessed the ISO will consider conducting studies on these years or utilize past studies[10] in the areas as appropriate.

4.4 Study Areas

The reliability assessments will be performed on the bulk system (north and south) as well as the local areas under the ISO controlled grid. Figure 4.4-1 shows the approximate geographical locations of these study areas. The full-loop power flow base cases that model the entire WECC 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
    - Metro area.
- San Diego Gas Electric (SDG&E) main transmission
- San Diego Gas Electric (SDG&E) sub-transmission
- Valley Electric Association (VEA) area
- ISO overall bulk system

[8] 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.
[9] System peak load conditions for one of the years and the rationale for why that year was selected.
[10] 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.

Figure 4.4-1: Approximated geographical locations of the study areas

4.5 Transmission Assumptions

4.5.1 Transmission Projects

The transmission projects that the ISO 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 ISO approval in the 2016-2017 or earlier ISO transmission plans. Currently, the ISO anticipates the 2016-2017 transmission plan will be presented to the ISO board of governors for approval in March 2017. Projects with potential significant scope change will not be modeled in the starting base case.

4.5.2 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 A4-1 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 ISO secured website.

4.5.3 Protection System

To help ensure reliable operations, many Remedial Action Schemes (RAS), Protection Systems, safety nets, UVLS and 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 SPS, 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 ISO, in its 2016-2017 TPP, started modeling RAS in power flow studies as they were made available by the PTOs. The ISO will continue the effort of modeling RAS in this cycle in working with PTOs with a target to have model for all RAS in the ISO controlled grid.

4.5.4 Control Devices

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

- All shunt capacitors in SCE and other areas
- 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 line such as PDCI, IPPDC, and Trans Bay Cable Projects
- Imperial Valley phase shifting transformers

4.6 Load Forecast Assumptions

4.6.1 Energy and Demand Forecast

The assessment will utilize the California Energy Demand Updated Forecast 2017-2027 adopted by California Energy Commission (CEC) on January 25, 2017 using the Final LSE and BA Table Mid Baseline spreadsheet[11] submitted on January 12, 2017.

During 2016, the CEC, CPUC and ISO engaged in collaborative discussion on how to consistently account for reduced energy demand from energy efficiency in the planning and procurement processes. To that end, the 2016 IEPR final report, adopted on February 15, 2017, based on the IEPR record and in consultation with the CPUC and the ISO, recommends using the Mid Additional Achievable Energy Efficiency (AAEE) scenario for system-wide and flexibility studies for the CPUC LTPP and ISO TPP cycles. However, for local area studies, because of the local nature of reliability needs and the difficulty of forecasting load and AAEE at specific locations and estimating their daily load-shape impacts, using the Low AAEE scenario is more prudent at this time.

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

https://efiling.energy.ca.gov/getdocument.aspx?tn=215745

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

- The 1-in-10 weather year, mid demand baseline case with low AAEE savings load forecasts will be used in PG&E, SCE, SDG&E, and VEA local area studies including the studies for the local capacity requirement (LCR) areas.
- The 1-in-5 weather year, mid demand baseline with mid AAEE savings load forecast will be used for system studies

The California Energy Demand Updated Forecast 2017-2027 includes Peak-Shift Scenario Analysis and states the following with respect to the use results of this analysis in the ISO TPP studies:

"The results of the final adjusted managed peak scenario analysis can be used by the California ISO in TPP studies to review previously -approved projects or procurement of existing resource adequacy resources to maintain local reliability but should not be used in identifying new needs triggering new transmission projects, given the preliminary analysis. More complete analyses will be developed for IEPR forecasts once full hourly load forecasting models are developed."[12]

In the 2017-2018 TPP, the ISO will use the CEC energy and demand forecast for the baseline scenario analysis identified in section 4.11.1. As the ISO conducts sensitivities on a case by case basis and to comply with the NERC TPL-001-4 mandatory reliability standard, these and other forecasting uncertainties will be taken into account in the sensitivity studies identified in section 4.11.2 as needed. The ISO will continue to work with the CEC on the hourly load forecast issue during the development of 2017 IEPR.

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[11] http://www.energy.ca.gov/2016_energypolicy/documents/2016-12-08_workshop/LSE-BA_Forecasts.php

[12] CEC California Energy Demand 2016-2026, Revised Electricity Forecast Volume1: Statewide Electricity Demand and Energy Efficiency, January 2016, http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-05/TN215275_20170112T135223_California_Energy_Demand_Updated_Forecast_20172027.pdf, Page 51.

4.6.2 Methodologies to Derive Bus Level Forecast

Since load forecasts from the CEC are generally provided for a larger area, these load forecasts may 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 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.

4.6.2.1 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.

Determination of Division Loads

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

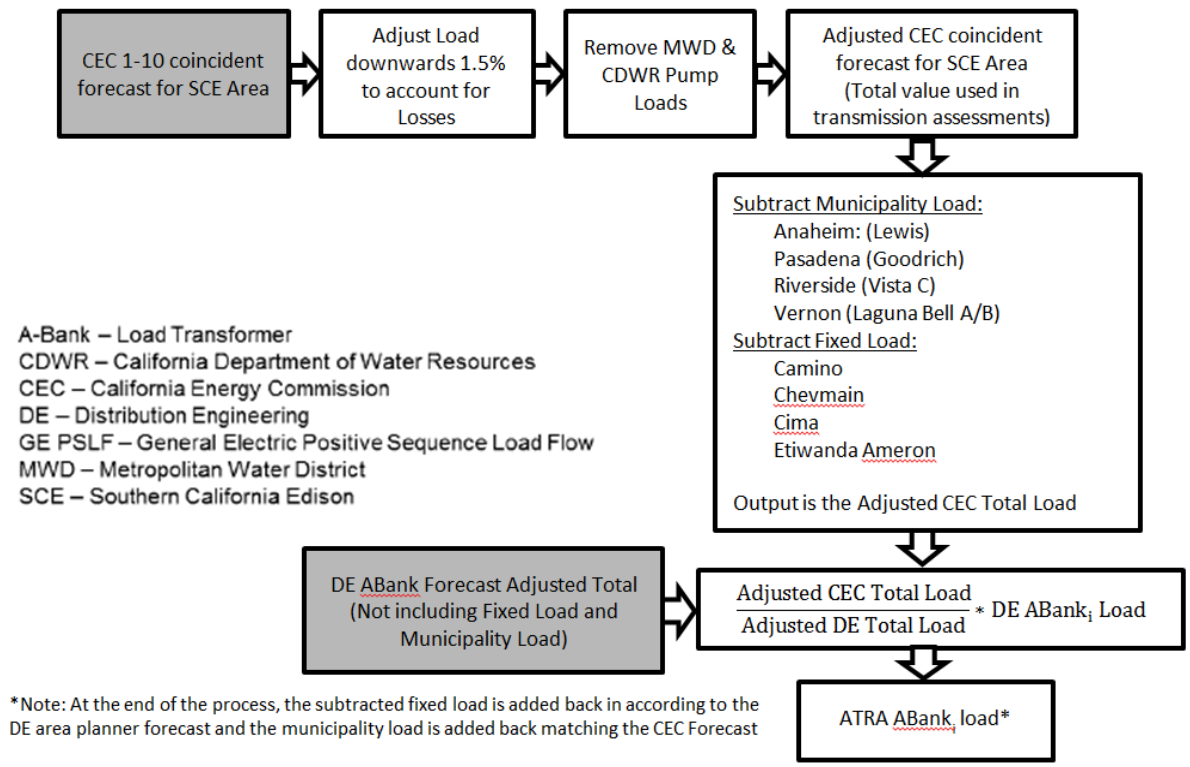
Municipalities provide PG&E their load forecast information. If no information is provided, PG&E supplements such forecast. For example, if a municipal utility provided only the 1-in-5 loads, PG&E would determine the 1-in-2 and 1-in-10 loads by adjusting the 1-in-5 loads for temperature in the same way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

4.6.2.2 Southern California Edison Service Area

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

Figure 4-2: SCE A-Bank load model



4.6.2.3 San Diego Gas and Electric Service Area

The substation load forecast reflects the actual, measured, maximum coincident load on the substation distribution transformers. This max load is obtained either from SCADA historical data or in a few cases from mechanical charts. That measured max load is then weather normalized to produce the adverse substation load. The adverse substation loads 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 adverse load, and the coincident load.

The distribution substation annual load forecast uses the actual peak load on the low side of each substation bank transformer or transformers if running in parallel. Once the peaks are determined, weather factors, i.e. normalizing and 'adversing' factors are applied to the peaks.

The Normalizing Factor is used to take the Total MVA for the summer and adjust it to a normal year (50/50) value.

- 50/50 value – the value you would expect 5 years out of 10.

- If the weather condition on the summer peak date was abnormally hot, the normalizing factor would be <1.0.
- If the weather condition on the summer peak date was abnormally cool, the normalizing factor would be >=1.0
- Normalized Peak = Total Peak MVA * Normalizing Factor

The Adverse Factor takes the normalized peak value and 'adverses' it up to what the load would be if the peak occurred in an adverse year.

- The adverse peak is the adjusted peak that would be expected 1 out of 10 years.
- Adverse Peak = Normalized Peak * Adverse Factor

The distribution substation annual forecast submitted to transmission planning is an Adverse Peak forecast. The distribution substation forecast will always be higher than the system forecast which is a coincident forecast that is 'adversed'. The distribution circuits are de-coupled from the substation banks and buses, and are therefore not used to complete the substation forecast.

4.6.2.4 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 adjusted with future known load changes. The CEC develops Statewide Energy Demand Forecasts, who may adjust VEA's forecast for weather, energy efficiency or other forecast considerations. VEA then compares its forecast with the CEC forecast when developing forecasts for the various TPP case forecasts.

4.6.2.5 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.

4.6.3 Power Factor Assumptions

In the SCE area assessment, an active to reactive power (watt/var) ratio of 25-to-1 (or power factor of 0.999) measured at the high side of the A-Bank (230/115 kV or 230/66 kV) will be assumed for the SCE transmission substation loads.

The watt/var ratio is a result of SCE commitment to its program to optimize reactive power planning and capacitor bank availability during heavy summer peak load periods in its distribution and sub-transmission systems. The objective of the SCE's reactive power program was to ensure a watt/var ratio of 25 to 1.

In the SDG&E area, power factors at all substations will be modeled using the most recent historical values obtained at peak loads. Bus load power factor for the year 2017 and 2018 will be modeled based on the actual peak load data recorded in the EMS system. For the subsequent study years a power factor of 0.992 will be used.

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 the year 2019 will be modeled based on the actual data recorded in the EMS system. For the subsequent study years a power factor of 0.99 lagging for summer peak cases, and unity power factor for spring off-peak cases, 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 both near-term and long-term TPP cases.

4.6.4 Self-Generation

Peak demand in the CEC demand forecast is reduced by projected impacts of self-generation serving on-site customer load. The self-generation is further categorized as PV and non-PV. Statewide, self-generation is projected to reduce peak load by more than 8,078 MW in the mid case by 2027. In 2017-2018 TPP base cases, the PV component of self-generation will be modeled as discrete element. Self-generation peak impacts for PG&E, SCE and SDG&E planning areas are shown in Table 4.6-1.

Table 4.6-1: PG&E, SCE & SDG&E Planning Areas PV Self-Generation Peak Impacts (MW)

	CEDU 2016 Mid Demand		
	PG&E	SCE	SDG&E
2018	1,001	823	304
2019	1,068	902	327
2020	1,141	981	348
2021	1,226	1,074	372
2022	1,328	1,186	400
2023	1,447	1,315	431
2024	1,581	1,458	464
2025	1,728	1,616	500
2026	1,886	1,787	537
2027	2,050	1,960	574

The CEC self-generation information is available on the CEC website at:
http://www.energy.ca.gov/2016_energypolicy/documents/2016-12-08_workshop/mid_demand_case.php

PV Self-generation installed capacity for mid demand scenario by the PTO and forecast climate zones are shown in Table 4.6-2.

Table 4.6-2: PV self-generation installed capacity by PTO[13]

PTO	Forecast Climate Zone	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
PG&E	Central Coast	226	226	266	290	318	350	385	423	464	505
	Central Valley	636	636	721	776	841	914	994	1081	1174	1267
	Greater Bay Area	876	876	1054	1164	1290	1433	1590	1760	1941	2122
	North Coast	266	266	321	354	391	433	480	529	582	635
	North Valley	150	150	166	176	188	203	219	237	257	277
	Southern Valley	749	749	817	862	917	982	1055	1137	1226	1316
	PG&E Total	2903	2903	3343	3622	3944	4315	4724	5166	5644	6121
SCE	Big Creek East	231	243	254	269	288	310	334	361	391	420
	Big Creek West	166	180	193	214	239	269	302	339	380	421
	Eastern	526	582	634	697	770	851	940	1038	1142	1247
	LA Metro	902	1003	1105	1234	1386	1558	1747	1958	2182	2406
	Northeast	358	393	427	467	512	562	616	676	740	803
	SCE Total	2183	2400	2614	2881	3195	3550	3939	4373	4834	5296
SDG&E	SDG&E	806	867	927	997	1077	1164	1257	1356	1459	1563

Output of the self-generation 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.

PV Peak Shift

The California Energy Demand Updated (CEDU) Forecast 2017-2027 also included analysis of potential peak-shift scenario and resulting impact on peak demand served by utilities for the IOU planning areas for the managed forecast (that is, the mid baseline case combined with mid AAEE). The CEC recommends using results of the final adjusted managed peak scenario analysis in ISO's TPP studies to review previously -approved projects or procurement of existing resource adequacy resources to maintain local reliability but not be used in identifying new needs triggering new transmission projects, given the preliminary analysis. CEC plans to develop more complete analyses for IEPR forecasts once full hourly load forecasting models are developed.

Table 4.6-3 below shows final peak-shift adjustments for each IOU planning areas.

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

Table 4.6-3: Final Peak-Shift Adjustment for PG&E, SCE and SDG&E planning areas

Year	PG&E	SCE	SDG&E
2016	--	--	--
2017	136	118	69
2018	273	236	138
2019	409	354	207
2020	545	472	277
2021	682	590	346
2022	818	708	415
2023	955	826	484
2024	1,091	944	553
2025	1,227	1,062	622
2026	1,364	1,180	691
2027	1,500	1,298	760

Source: California Energy Demand Updated Forecast, 2017-2027

https://efiling.energy.ca.gov/getdocument.aspx?tn=215745

4.7 Generation Assumptions

4.7.1 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 five levels below:

- Level 1: Under construction
- Level 2: Regulatory approval received
- Level 3: Application under review
- Level 4: Starting application process
- Level 5: Press release only

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

Up to 1-year Operating Cases: Only generation that is under construction (Level 1) and has a planned in-service date within the time frame of the study will be modeled in the initial power flow case.

2-5-year Planning Cases: Generation that is under construction (Level 1) and has a planned in-service date within the time frame of the study will be modeled in the initial power flow case.

Conventional generation in pre-construction phase with executed LGIA and progressing forward will be modeled off-line but will be available as a non-wire mitigation option.

OTC repowering projects will be modeled in lieu of existing resources as long as they have power purchase approval from the CPUC or other Local Regulatory Agency (LRA).

Renewable generation with all permitting and necessary transmission approved and expected to be in-service within 5-years may also be modeled in the relevant cases. The CPUC's discounted core and ISO's interconnection agreement status will be utilized as criteria for modeling specific generation. For 2021, generation from the CPUC and CEC provided portfolios described below will be used, as necessary, to ensure generation needed to be in-service to meet the 33% RPS requirement is represented. Given the data availability, generic dynamic data may be used for this future generation.

6-10-year Planning Cases: Only generation that is under construction or has received regulatory approval (Levels 1 and 2) will be modeled in the area of interest of the initial power flow case. If additional generation is required to achieve an acceptable initial power flow case, then generation from Levels 3, 4, and 5 may be used. However, generally Level 3, 4, and 5 generation should only be used when they are outside the area of study, so that the generation's impact on the facility addition requirements will be minimized.

4.7.2 Renewable Generation

The RPS portfolio that was supplied by Commission staff to the ISO for the 2016-2017 TPP, "33% 2025 Mid AAEE" trajectory portfolio will be used in the 2017-2018 TPP. The ISO may supplement the scenario with information regarding contracted RPS projects that have begun construction since May 2016.

4.7.2.1 Renewable generation dispatch

The ISO has done a qualitative and quantitative assessment of hourly Grid View renewable output for stressed conditions during hours and seasons of interest. Available data of pertinent hours was catalogued by renewable technology and location on the grid. The results of active power output differ somewhat between locations and seasons as follows. Reactive limits of renewable generation will be as specified by Qmax and Qmin, which rely upon technology of the generation and may change as a function of active power output and power factor specified.

Table 4.7-1: Summary of renewable output in PG&E

All years	Biomass/Biogas/Geothermal	Solar PV, ST	Wind	Stressed case
Sum Min Load	NQC~=P Max	0	3xNQC~=Pmax	High Output
Sum Off-Peak	NQC~=P Max	NQC~=Pmax	3xNQC~=Pmax	High Output
Sum Partial-Peak	NQC~=P Max	0	0	Low Output
Sum Peak	NQC~=P Max	25%xNQC~=25%xPmax	NQC~=33%xPmax	Low Output
Winter Peak	NQC~=P Max	0	50%xNQC~=16.6%xPmax	Low Output

Table 4.7-2: Summary of renewable output in SCE

	Biomass/Biogas/Geothermal	Solar PV, ST	Wind	Stressed case
Sum Min Load	NQC~=P Max	0	2.8xNQC~= 93%xPmax	High Output
Sum Off-Peak	NQC~=P Max	93%xNQC~=93 %xPmax	2.8xNQC~= 93%xPmax	High Output
Sum Partial- Peak	NQC~=P Max	TBD	TBD	Low output
Sum Peak	NQC~=P Max	36%xNQC~=36 %xPmax	0	Low Output

Table 4.7-3: Summary of renewable output in SDG&E

All years	Biomass/Biogas/Geothermal	Solar PV, ST	Wind	Stressed case
Sum Min Load	NQC~=P Max	0	3xNQC~=Pmax	High Output
Sum Off-Peak	NQC~=P Max	81%xNQC~=81 %xPmax	2.9xNQC~= 96%xPmax	High Output
Sum Peak	NQC~=P Max	55%xNQC~=55 %xPmax	NQC~= 33%xPmax	Low Output

Table 4.7-4: Summary of renewable output in VEA

All years	Biomass/Biogas/Geothermal	Solar PV, ST	Wind	Stressed case
Sum Min Load	NQC~=P Max	0	N/A	High Output
Sum Off-Peak	NQC~=P Max	97%xNQC~=97 %xPmax	N/A	High Output
Sum Peak	NQC~=P Max	47%xNQC~=47 %xPmax	N/A	Low Output

4.7.3 Thermal generation

For the latest updates on new generation projects, please refer to CEC website under the licensing section (http://www.energy.ca.gov/sitingcases/all_projects.html) the ISO relies on other databases to track the statuses of additional generator projects to determine the starting year new projects may be modeled in the base cases. Table A2-1 of Appendix A lists new thermal generation projects in construction or pre-construction phase that will be modeled in the base cases.

4.7.4 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 area is a local capacity requirement area that relies on Big Creek generation to meet NERC Planning Standards. The Sierra, Stockton and Greater Fresno local capacity areas in the PG&E system also rely on hydroelectric generation. For these areas, the

ISO will consider drought conditions when establishing the hydroelectric generation production levels in the base case assumptions.

4.7.5 Generation Retirements

Existing generators that have been identified as retiring are listed in Table A3-1 of Appendix A. 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[14],
- Once Through Cooled Retirements – As identified in section 4.7.6.
- Renewable and Hydro Retirements – Assumes these resource types stay online unless there is an announced retirement date.
- Other Retirements – Unless otherwise noted, assumes retirement based resource age of 40 years or more. Table A3-2 of Appendix A includes a list of generators that will be modeled offline based on this criterion unless they have an existing contract that runs beyond their assumed retirement age.

4.7.6 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 4.7-5;
- All other OTC generating units will be modeled off-line beyond their compliance dates;

Potential early retirements of some OTC generating units to accommodate repowering projects, which have the CPUC approval for PPTAs and environmental review well under way at the CEC, are listed in Table A3-3 of Appendix A.

. http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=158117030

Table 4.7-5: Once-through cooled generation in the California ISO BAA

Area	Generating Facility (Total Plant MW)	Owner	Unit	State Water Resources Control Board (SWRCB) Compliance Date	Net Qualifying Capacity (NQC) (MW)	Notes
Humboldt LCR Area	Humboldt Bay (135 MW)	PG&E	1	12/31/2010	52	Retired 135 MW (Mobile 2&3 non-OTC) and repowered with 10 CTs (163 MW) - (July 2010)
			2	12/31/2010	53	
Greater Bay Area LCR	Contra Costa (674 MW)	GenOn	6	12/31/2017	337	Replaced by Marsh Landing power plant (760 MW) – (May 2013)
			7	12/31/2017	337	
	Pittsburg (1,311 MW) Unit 7 is non-OTC	GenOn	5	12/31/2017	312	On October 3, 2016, NRG Delta sent a letter to the CPUC to notify that it planned to shut down permanently retire Units 5 and 6 as early as January 1, 2017. NRG Delta also notified the SWRCB that it permanently ceased once-through-cooling operation for these units by the end of the day of December 31, 2016. All three units, including Unit 7, have been ceased operation.
			6	12/31/2017 (see notes)	317	
	Potrero (362 MW)	GenOn	3	10/1/2011	206	Retired 362 MW (Units 4, 5 & 6 non-OTC)
Central Coast (non-LCR area) *Non-LCR area has no local capacity requirements	Moss Landing (2,530 MW)	Dynegy	1	12/31/2020*	510*	* Per Dynegy's Settlement Agreement with the SWRCB, executed on October 9, 2014, the Moss Landing generating units will have until December 31, 2020 to be brought into compliance. Dynegy will pursue Track 2 compliance for Units 1 and 2 by installing technology control and implementing operational control to reduce impingement mortality and entrainment. Upon January 1, 2021, the capacity of Units 1 and 2 will also be de-rated by 15%. In its January 5, 2017 letter to the SWRCB, Dynegy indicated that it no longer intended to achieve Track 2 compliance for Units 6 and 7 and instead intended to retire both units. Dynegy stated that it shut down Units 6 and 7 on January 1, 2017.
			2	12/31/2020*	510*	
			6	12/31/2020 (see notes)	754	
			7	12/31/2020 (see notes)	756	
	Morro Bay (650 MW)	Dynegy	3	12/31/2015	325	Retired 650 MW (February 5, 2014)
			4	12/31/2015	325	
	Diablo Canyon (2,240 MW)	PG&E	1	12/31/2024	1122	On June 21, 2016, PG&E has announced that it planned to retire Units 1 and 2 by 2025.
			2	12/31/2024	1118	
Big Creek-Ventura LCR Area	Mandalay (560 MW)	GenOn	1	12/31/2020	215	Unit 3 is non-OTC
			2	12/31/2020	215	
	Ormond Beach (1,516 MW)	GenOn	1	12/31/2020	741	
			2	12/31/2020	775	
Los Angeles (LA) Basin LCR Area	El Segundo (670 MW)	NRG	3	12/31/2015	335	Replaced by El Segundo Power Redevelopment (560 MW) – (August 2013)
			4	12/31/2015	335	Unit 4 was retired on December 31, 2015.
	Alamitos	AES	1	12/31/2020	175	

Area	Generating Facility (Total Plant MW)	Owner	Unit	State Water Resources Control Board (SWRCB) Compliance Date	Net Qualifying Capacity (NQC) (MW)	Notes
	(2,011 MW)		2	12/31/2020	175	On November 19, 2015, the CPUC, with Decision 15-11-041, approved 640 MW combined-cycle generating facility repowering project for AES Alamitos Energy, LLC. This authorizes Power Purchase and Tolling Agreement (PPTA) between SCE and AES Southland
			3	12/31/2020	332	
			4	12/31/2020	336	
			5	12/31/2020	498	
			6	12/31/2020	495	
	Huntington Beach (452 MW)	AES	1	12/31/2020	226	On November 19, 2015, the CPUC, with Decision 15-11-041, approved a repowering project for a 644 MW combined-cycle generating facility for AES Huntington Beach, LLC. This authorizes Power Purchase and Tolling Agreement (PPTA) between SCE and AES Southland,
			2	12/31/2020	226	
			3	12/31/2020	227	Retired 452 MW and converted to synchronous condensers (2013). Modeled as off-line in the post 2017 studies as contract expires.
			4	12/31/2020	227	
	Redondo Beach (1,343 MW)	AES	5	12/31/2020	179	
			6	12/31/2020	175	
			7	12/31/2020	493	
			8	12/31/2020	496	
	San Onofre (2,246 MW)	SCE/ SDG&E	2	12/31/2022	1122	Retired 2246 MW (June 2013)
			3	12/31/2022	1124	
San Diego/I.V. LCR Area	Encina (946 MW)	NRG	1	12/31/2017	106	NRG proposed repowering with a new 500 MW project (Carlsbad Energy Center) – this was approved by the CPUC with the Decision 15-05-051 on May 21, 2015 and issued on May 29, 2015. NRG has stated that Encina Unit 1 would retire early (by March 31, 2017 at the latest) to allow for construction of the Carlsbad Energy Center interconnection facilities.
			2	12/31/2017	103	
			3	12/31/2017	109	
			4	12/31/2017	299	
			5	12/31/2017	329	
	South Bay (707 MW)	Dynegy	1-4	12/31/2011	692	Retired 707 MW (CT non-OTC) – (2010-2011)

4.7.7 LTPP Authorization Procurement

OTC replacement local capacity amounts in southern California that were authorized by the CPUC under the LTTP Tracks 1 and 4 will be considered along with the procurement activities to date from the utilities. Table 4.7-6 provides the local capacity resource additions and the study year in which the amounts will be first modeled based on the CPUC LTPP Tracks 1 and 4 authorizations. Table 4.7-7 provides details of the study assumptions using the utilities' procurement activities to date, as well as the ISO's assumptions for potential preferred resources for San Diego area.

Table 4.7-6: Summary of 2012 LTPP Track 1 & 4 Maximum Authorized Procurement[15]

LCR Area	LTTP Track-1		LTTP Track-4[16]	
	Amount (MW)(1)	Study year in which addition is to be first modeled	Amount (MW) (1)	Study year in which addition is to be first modeled
Moorpark Sub-area	290	2021	0	N/A
West LA Basin / LA Basin	1400-1800	2021	500-700	2021
San Diego	308	2018	500-800	2018

(1) Amounts shown are total including gas-fired generation, preferred resources and energy storage

[15] Maximum authorized procurement is different than approved contract (i.e., Power Purchase & Tolling Agreement) procurement. Maximum authorized procurement is the ceiling amount authorized by the CPUC without specific contracts. The approved PPTA procurement is the selected procurement with specific contracts between the LSE and the provider that have been approved by the CPUC for actual execution.

[16] CPUC Decision for LTPP Track 4 (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K008/89008104.PDF)

Table 4.7-7: Summary of 2012 LTPP Track 1 & 4 Procurement 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[17]	124.04	37.92	263.64	5	1,382	1,812.60
SCE's procurement for the Moorpark sub-area[18]	6.00	5.66	0.50	0	262	274.16
SDG&E's procurement	22.4*	0	25**-84*	33.6*	800[19]	881-940

Notes:

* Proxy preferred resource and energy storage assumptions are based on the maximum total amount of 140 MW that SDG&E is soliciting based on its 2016 RFO for Local Capacity Requirements Decision established by the CPUC via D.14-03-004 (the "Track 4" Decisions). These will be updated upon SDG&E's filing of final procurement selection for preferred resources and energy storage at the CPUC later in 2016 time frame.

** Based on the CPUC draft Scenarios and Assumptions for the 2016 LTPP and the 2017-2018 Transmission Planning Process, 25 MW will be assumed initially for the energy storage for San Diego and this amount can be increased (up to the net amount of the ceiling for preferred resources and energy storage subtracting other assumptions for LTPP related for preferred resources) if needed.

*** Pio Pico (300 MW) and Carlsbad Energy Center (500 MW) were approved by the CPUC as part of SDG&E-selected procurement for LTPP Tracks 1 and 4.

As proxy, generic resources, at the existing sites, will be used for modeling purposes up to the total conventional capacity authorized in LTTP Track-1 and Track-4 decisions until such time as new resource models, with CEC license, signed GIA and in good standing, become available. For further details on new resources see Table A2-1 "Planned generation". 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.

[17] 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.

[18] SCE-selected RFO procurement (A. 14-11-016) for the Moorpark sub-area is currently at the CPUC for review and consideration.

[19] The CPUC, in Decisions 14-02-016 and 15-05-051 approved PPTAs for the Pio Pico and Carlsbad Energy Center projects.

4.8 Preferred Resources

According to tariff Section 24.3.3(a), the ISO 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. In response, the ISO received demand response and energy storage information for consideration in planning studies from the following:

- California Public Utilities Commission (CPUC)
- Pacific Gas & Electric (PG&E)

CPUC staff made the following recommendations with regard to demand response (DR) assumptions appropriate for use in the 2016-17 TPP studies.

1. Demand response assumptions used in the TPP should reflect the guidelines described in the CPUC's ruling on standardized planning assumptions and scenarios.
2. The TPP studies should use the allocations of demand response capacity to bus bar provided by the IOUs.
3. The TPP studies should count any new demand response capacity specifically contracted by the IOUs, and approved by the CPUC, to fulfill local capacity needs and other demand response procurement mechanisms.
4. The CAISO should continue to participate in the CPUC's Demand Response rulemaking to better inform program development and future policy direction.

PG&E provided a bus-level model of PG&E's demand response (DR) programs for the inclusion in the Unified Planning Assumptions and 2017-2018 study plan.

4.8.1 Methodology

The ISO issued a paper[20] 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 ISO's transmission plan as an alternative to the conventional transmission or generation solution.

In previous planning cycles, the ISO 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 Moor Park areas. In addition to these efforts focused on the overall LA Basin and San Diego needs, the ISO also made further progress in integrating preferred resources into its reliability analysis focusing on other areas where reliability issues were identified.

As in the 2015-2016 planning cycle, reliability assessments in the current planning cycle will consider a range of existing demand response amounts as potential mitigations to transmission constraints. The reliability studies will also incorporate the incremental uncommitted energy efficiency amounts as projected by the CEC, distributed generation based on the CPUC

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

Commercial-Interest RPS Portfolio and a mix of preferred resources including energy storage based on the CPUC LTPP 2012 local capacity authorization. These incremental preferred resource amounts are in addition to the base amounts of energy efficiency, demand response and "behind the meter" distributed or self-generation that is embedded in the CEC load forecast.

For each planning area, reliability assessments will be initially performed using preferred resources other than energy-limited preferred resources such as DR and energy storage to identify reliability concerns in the area. If reliability concerns are identified in the initial assessment, additional rounds of assessments will be performed using potentially available demand response and energy storage to determine whether these resources are a potential solution. If these preferred resources are identified as a potential mitigation, a second step - a preferred resource analysis may then be performed, if considered necessary given the mix of resources in the particular area, to account for the specific characteristic of each resource including use or energy limitation in the case of demand response and energy storage. An example of such a study is the special study the ISO performed as part of the 2016-2017 planning cycle to assess the availability requirements of energy-limited, slower-response resources such as DR to be considered for local resource adequacy on the basis of pre-contingency dispatch. The ISO will continue to use the methodology developed as part of the study to evaluate these types of resources.

4.8.2 Demand Response

In reliability studies, only capacity from DR programs that can be relied upon to mitigate "first contingencies", as described in the 2012 LTPP Track 4 planning assumptions, are counted. DR that can be relied upon to mitigate post first contingencies in local reliability studies participates in, and is dispatched from, the ISO market in sufficiently less time than 30 minutes[21] from when it is called upon.

There is uncertainty as to what amount of DR can be projected to meet this criteria within the TPP planning horizon given that few current programs meet this criteria and the current DR Rulemaking R.13-09-011 expects to restructure DR programs to better meet ISO operational needs and has already produced one major policy decision towards that goal.[22] The rulemaking is expected to issue additional decisions that enable demand response to be more useful for grid needs, but ISO has several tasks it must complete in order to make integration of DR possible.

The DR Load Impact Reports filed with the CPUC on April l, 20l6, and other supply-side DR procurement incremental to what is assumed in the Load Impact Reports, 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. The following table describes the total supply-side DR capacity assumptions.

[21] The 30 minute requirement is based on meeting NERC Standard TOP-004-02. Meeting this requirement implies that programs may need to respond in 20 minutes, from customer notification to load reduction, in order to allow for other transmission operator activities in dealing with a contingency event.

[22] Commission Decision 14-03-026 approved the bifurcation of DR programs into two categories: Supply DR (DR that is integrated into ISO markets and dispatched when and where needed) and Load-Modifying DR (DR that is not integrated into ISO markets. This decision determined that bifurcation will occur by 2017.

Table 4.8-1: Existing DR Capacity Range in Local Area Reliability Studies

DR not embedded in IEPR demand forecast (values in MW):	PG&E	SCE	SDG&E	All IOUs	Assumed Market Participation	Assumed to respond within 30 minutes
Base Interruptible	255	607	1.4	863.4	RDRR	Yes
Agricultural Pumping Interruptible	-	63	-	63	RDRR	Yes
AC Cycling Residential	54	218	11.5	277	PDR	Yes
AC Cycling Non-Residential	1	40	3.1	44.1	PDR	Yes
CPB	120	141	12.2	263	PDR	No
DBP	0	0	0	0	PDR	No
AMP(DRC)	0	0	-	0	PDR	No
SCE LCR RFO	-	5	-	5	RDRR	Yes
DRAM	-	-	-	124.6	PDR	No

Given the uncertainty as to the DR amount that can be relied upon for mitigating first contingencies, the CAISO's 2014-15 and 2015-16 TPP Base Local Capacity Reliability Area studies examined two scenarios: one consistent with the 2012 LTPP Track 4 DR assumptions and one consistent with the 2014 LTPP DR assumptions of available 30- minute-responsive DR. A similar two scenario approach will be used in the 2017-2018 TPP; that is, one scenario assuming a base level of DR capacity based on a response time of 20 minutes to meet first contingencies[23], followed by a second scenario assuming full availability of the 30-minute-responsive DR described in Table 4.8-1 above - to the extent that DR is physically located in the Local Capacity Reliability Area being studied.

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

Table 4.8-2: Factors to Account for Avoided Distribution Losses

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

[23] In the 2016-2017 planning cycle SCE indicated that 475 MW of DR in SCE's service territory meets the 20-minute response time for mitigating contingency reliability concerns.

4.8.3 Energy Storage

CPUC Decision (D.)13-10-040 established a 2020 procurement target of 1,325 MW installed capacity of new energy storage units within the ISO planning area. Of that amount, 700 MW shall be transmission-connected, 425 MW shall be distribution-connected, and 200 MW shall be customer-side. D.13-10-040 also allocates procurement responsibilities for these amounts to each of the three major IOUs. Energy storage that will be procured by SCE and SDG&E to fill the local capacity amounts authorized under the CPUC 2012 LTPP decision is subsumed within the 2020 procurement target.

Table 4.8-3: Total Energy Storage Procured To-Date

Domain	Transmission-connected	Distribution-connected	Customer-connected
SDG&E	40	44	20
SCE	55	204	199
PG&E	60	16	4
Total	155	264	268

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.

The following table includes battery energy storage system projects that were approved by the CPUC in response to Resolution E-4791, issued to address electrical reliability risks due to the moratorium on injections into the Aliso Canyon Natural Gas Storage Facility. These battery energy storage system projects were planned to be placed in-service in early 2017 timeframe. These projects are also included in Tables 4.8-6 and 4.8-7.

Table 4.8-4: Summary of fast-tracked battery energy storage system projects related to Aliso Canyon gas storage constraint

	Name	Load Serving Entity	Type	Capacity (MW)	Point of Interconnection	Bus No.	Commercial Operating Date
1	Alta Gas Peaker/BESS (WDT 1250)	SCE	Hybrid Gas/BESS	42.7/20	Chino 66kV	24024	Jan-17
					Modeled via 13.8kV gen-tie to Simpson gen bus	24140	
2	Mira Loma A+B BESS	SCE	BESS	42.7/20	Mira Loma West 66kV	24210	Jan-17
					Modeled via 12kV gen-tie		

	Name	Load Serving Entity	Type	Capacity (MW)	Point of Interconnection	Bus No.	Commercial Operating Date
3	Center Peaker/BESS	SCE	Hybrid Gas/BESS	47.13/10	Center 66kV	24203	Jan-17
					Modeled next to Center peaker gen	29308	
4	Grapeland Peaker/BESS	SCE	Hybrid Gas/BESS	44.55/10	Etiwanda 66kV	24055	Jan-17
					Modeled next to Etiwanda peaker gen	29305	
5	WDT1406	SCE	BESS	2	Santiago 66kV	24133	Jan-17
					Modeled via 12kV gen-tie		
6	WDT1200A	SCE	BESS	10	Santa Clara 66kV	24127	Jan-17
					Modeled via 12kV gen-tie		
7	Escondido	SDG&E	BESS	3x10	Escondido 69kV	22256	Early 2017
8	El Cajon	SDG&E	BESS	7.5	El Cajon 69kV	22208	Early 2017

As the 2017-2018 TPP studies identify transmission constraints in the local areas, the ISO will identify the effective busses that the storage capacity identified in the table below can be distributed amongst within the local area as potential development sites. Table 4.8-4 describes the assumptions that shall be used for the technical characteristics and accounting of the three classes of storage mandated by D.13-10-040

Table 4.8-5: Residual Energy Storage Procurement to Meet D.13-10-040 Targets (MW)

Domain	**Transmission-connected**	**Distribution-connected#**	**Customer- side**
Total Installed Capacity	545	160	0
Amount providing RA capacity	545	160	0
Amount providing flexibility	545	160	0
Amount with 2 hours of storage	218	64	0
Amount with 4 hours of storage	218	64	0
Amount with 6 hours of storage	109	32	0
Charging rate: If a unit is discharged and charged at the same power level, assume it takes 1.2 times as long to charge as it does to discharge. Example: 50 MW unit with 2 hours of storage. If the unit is charged at 50 MW, it will take 2.4 hours to charge. If the same unit is charged at 25 MW, it will take 4.8 hours to charge.			

The residual energy storage capacity amounts will not be included in the initial reliability analysis. The storage capacity amounts will be used as potential mitigation in those planning areas where reliability concerns have been identified. If the energy storage project has a two-hour depth then it is de-rated by 50% in order to convert its MW into the amount of capacity actually counting towards RA (since by RA rules output must be sustained for minimum four hours. The CPUC has provided locational information for the storage resources for the PG&E, SCE and SDG&E area in Tables 4.8-5, 4.8-6 and Table 4.8-7.

Table 4.8-6: Locational Information for Energy Storage Resources in PG&E Area

PG&E Energy Storage Resources

Counterparty (Project Name)	Point of Interconnection (POI)	Approximate Transmission Point of	Aproximate Nearest Resource ID (ResID)	Approximate Bus ID (BusID)	MW	Point of Connection
Amber Kinetics (Energy Nuevo)	New 70 kV position in PG&E New Kearney Substation	New 70 kV position in PG&E New Kearney Substation	KERNEY_6_LD1	34480_KEARNEY _70.0_LD1	20	Transmission
Convergent (Henrietta)	Henrietta Distribution Substation (12kV)	Henrietta 70kV Substation	HENRTA_6_LD1	34540_HENRITTA_70.0_LD 1	10	Distribution
Hecate Energy (Molino)	Molino Transmission (69kV) Substation	Molino Transmission (69kV) Substation	MOLINO_6_LD1	31364_MOLINO _60.0_LD1	10	Transmission
NextEra Energy (Golden Hills)	Tesla Substation 115kV	Tesla Substation 115kV	TESLA_1_QF	33540_TESLA _115_GUM1	30	Transmission
Stem BTM	Customer Meter	Aggregated Sub Lap (TBD)	N/A	N/A	4	Customer
Yerba Buena Pilot Battery Project	21kV Swift 2102 Feeder (into Swift 21kV Substation)	Swift 115kV Substation	SWIFT_1_NAS (not yet operational)	35622_SWIFT _115_GUNS	4	Distribution
Vaca Dixon Pilot Battery Project	Vaca Dixon 12 kV Substation	Vaca Dixon 115kV Substation	VACADX_1_NAS	31998_VACA- DIX_115_GUNS	2	Distribution

Table 4.8-7: Locational Information for Energy Storage Resources in SCE Area

SCE's Energy Storage Projects Locational Information by Busbar & Attributes (MW)

	Project	Storage MW	Product Type	Locational Information	Bus ID	
LCR RFO 264 MW	Ice Bear	28.64	ES BTM PLS (customer-side)	N/A (Distributed)		
LCR RFO 264 MW	AES	100	IFOM (distribution)	**Point of Interconnection:** 230kV bus at the Alamitos A-Bank Substation **Bus Name:** ALMITOSW **Bus Number:** 24007		
LCR RFO 264 MW	Stem	85	ES BTM (customer-sde)	N/A (Distributed)		
LCR RFO 264 MW	Hybrid Electric	50	ES BTM (customer-sde)	N/A (Distributed)		
2016 ACES RFO/RFP	**Project**	**Storage MW**	**Product Type**	**Locational Information**		
2016 ACES RFO/RFP	Powin	2	IFOM (distribution)	**Point of Interconnection:** 12kV Virgo Distribution line (Santiago A Bank Substation)	66 kV +H11:H35Bus Name: SANTIAGO 66 kV Bus Number: 24133	*No bus number for 12 kV Bus. 66 kV bus where B-station that feeds circuit is located used
2016 ACES RFO/RFP	Western Grid [2]	5	IFOM (distribution)	**Point of Interconnection:** Wakefield Petit 16 kV Distribution line (Santa Clara A Bank Substation)	66 kV Bus Name: S.CLARA 66 kV Bus Number: 24127	
2016 ACES RFO/RFP	AltaGas	20	IFOM (distribution)	**Point of Interconnection:** Ganesha Simpson 66kV line Distribution line (Chino A Bank Substation)	66 kV Bus Name: CHINO 66 kV Bus Number: 24024	*No bus number for 66 kV Transmission Line Tap. Chino 66 kV bus utilzied
	Project	**Storage MW**	**Product Type**	**Locational Information**		
2016 ACES DBT	Tesla	20	IFOM (distribution)	**Point of Interconnection:** Mira Loma A Bank Substation	66 kV Bus Name: MIRALOMW 66 kV Bus Number: 24210	
PRP 2	**Project**	**Storage MW**	**Product Type**	**Locational Information**		
PRP 2	AMS CTEC 1-5	40	ES BTM (customer-sde)	N/A (Distributed)		
PRP 2	Convergent OCES 1-3	35	IFOM (Transmission)	**Point of Interconnectio:** Chestnut 66kV bus out of Johanna 220/66kV substation	66 kV Bus Name: JOHANNA 66 kV Bus Number: 24207	
PRP 2	Nextera OCES 1	8.5	ES BTM (customer-sde)	N/A (Distributed)		
PRP 2	Nextera OCES 2	1.5	ES BTM (customer-sde)	N/A (Distributed)		
PRP 2	SEF1	5	ES BTM (customer-sde)	N/A (Distributed)		
PRP 2	Valencia Energy Storage	10	IFOM (distribution)	**Point of Interconnection:** Aquarius 12 kV circuit Santiago 220/66kV substation	66 kV Bus Name: SANTIAGO 66 kV Bus Number: 24133	*No bus number for 12 kV Bus. 66 kV bus where B-station that feeds circuit is located used
PRP 2	HEJF1-2	15	IFOM (distribution)	**Point of Interconnection:** 12 kV bus at the Johanna substation	66 kV Bus Name: JOHANNA 66 kV Bus Number: 24207	*No bus number for 12 kV Bus. 66 kV bus where B-station that feeds circuit is located used
PRP 2	NRG Hybrid 1-5 [1]	10	ES BTM (customer-sde)	N/A (Distributed)		
Bilateral	**Project**	**Storage MW**	**Product Type**	**Locational Information**		
Bilateral	SCE EGT - Grapeland	10	IFOM (Transmission)	**Point of Interconnection:** Integrated with SCE's Grapeland Peaker	66 kV Bus Name: ETIWANDA 66 kV Bus Number: 24055 13.8 kV Bus Name: ETWPKGEN 13.8 kV Bus Number 29305 Project wil share same 13.8 kV Bus where exsting peaker is located.	
Bilateral	SCE EGT - Center	10	IFOM (Transmission)	**Point of Interconnection:** Integrated with SCE's Center Peaker	66 kV Bus Name: CENTER 66 kV Bus Number: 24203 13.8 kV Bus Name: CTRPKGEN 13.8 kV Bus Number 29308 Project wil share same 13.8 kV Bus where exsting peaker is located.	
ES RFO 16.3 MW	**Project**	**Storage MW**	**Product Type**	**Locational Information**		
ES RFO 16.3 MW	Stanton Energy Reliability Center	1.3	RA Only (distribution)	**Point of Interconnection:** Barre Substation **Bus Name:** BARRE **Bus Number:** 24201		
ES RFO 16.3 MW	Western Grid	10	RA Only (distribution)	**Point of Interconnection:** Wakefield Petit 16 kV Distribution line (Santa Clara A Bank Substation) **Bus Name:** S.CLARA **Bus Number:** 24127		
ES RFO 16.3 MW		5	RA Only (distribution)			
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	**Project**	**Grid Domain**	**MW in Plan**	**MW Actually Installed**	**A-Bank Substation**	**Bus Numbers at the 230kV used by TSP and CAISO**
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Tehachapi Storage	Distribution	8	8	Windhub 220/66	29407
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Irvine Smart Grid-Community Energy Storage	Distribution	0.03	0.03	Santiago 220/66	24134
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Irvine Smart Grid-Containerized Energy Storage	Distribution	2	2	Santiago 220/66	24134
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Irvine Smart Grid-Residential ES Unit	Customer	0.06	0.06	Santiago 220/66	24134
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Large Storage Test	Distribution	2	2	Barre 220/66	24016
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Discovery Museum	Distribution	0.1	0.1	Villa Park 220/66	24154
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Catalina Island	Distribution	1	1	N/A	N/A
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	V2G-LA AFB	Distribution	0.65	0.5	TBD	TBD
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Self-Generation Incentive Program	Customer	10.9	9.66	TBD	TBD
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Permanent Load Shifting	Customer	4.74	1.14	TBD	TBD
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Home Batter Pilot	Customer	0.08	0	N/A	N/A
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	Distribution Energy Storage Integration 1	Distribution	2.4	2.4	Villa Park 220/66	24154

[1] Although these agreements are for 2 MW each, only 1 MW of the capacity wil be comprised of storage as such only 1 MW is countable. (The remaining 1 MW is from renewable technology.)

[2] ACES Western Grid contract is an acceleration of the 2014 Energy Storage RFO Western Grid contract. As such, ACES Western Grid is not incremental to what is already counted for 2014 Energy Storage

Table 4.8-8: Locational Information for Energy Storage Resources in SDG&E Area

SDG&E's Energy Storage Projects Locational Information by Busbar & Attributes (MW)				
Domain	**Project Name**	**Capacity MW**	**Bus ID Number**	**Interconnection Substation**
Transmission	Lake Hodges Pumped Storage	40	22603	Lake Hodges LHM
Total Trasmission		**40 MW**		
Domain	**Project Name**	**Capacity / MW**	**Bus Number at Transmission Substation to which Distribution Circuit Connects**	**Interconection Substation**
Distribution	Escondido BESS 1	10	22256	Escondido
Distribution	Escondido BESS 2	10	22256	Escondido
Distribution	Escondido BESS 3	10	22256	Escondido
Distribution	El Cajon BESS 1	7.5	22208	El Cajon
Distribution	Borrego Microgrid Yard- SES1	0.5	22084	Borrego
Distribution	Pala Energy Storage Yard	0.5	22624	Pala
Distribution	Mission Valley- Skills Training Center	0.025	22496	Mission
Distribution	Clairemont	0.025	22136	Clairemont
Distribution	Poway	0.025	22668	Powey
Distribution	Borrego Springs CES	0.025	22084	Borrego
Distribution	Borrego Springs CES	0.025	22084	Borrego
Distribution	Borrego Springs CES	0.025	22084	Borrego
Distribution	Century Park CES	0.05	22372	Kearny
Distribution	Energy Inovation Center- Indoor	0.0045	22136	Clairemont
Distribution	Energy Inovation Center- Outdoor	0.01	22136	Clairemont
Distribution	San Diego Zoo	0.1	22868	Urban
Distribution	UCSD MESOM	0.006	22864	UCM
Distribution	Suites at Paseo (SDSU Private Dormitories)	0.018	21008	Stremview
Distribution	Del Lago Academy	0.1	22602	Olivenheim
Distribution	Ortega Highway 1243 SES1	1	22678	Margarita
Distribution	Ortega Highway 1243 SES2	1	22364	Margarita
Distribution	Pala Energy Storage Yard SES	1	22624	Pala
Distribution	Canyon Crest Academy	1	22581	North City West
Distribution	Borrego Microgrid Yard- SES2	1	22084	Borrego
Distribution	Santa Ysabel Substation	0.006	22736	Santa Ysabel
Distribution	Santa Ysabel Substation	0.03	22736	Santa Ysabel
Distribution	Del Lago Park & Ride	0.2		Felicita
Distribution	Integrated Test Facility	0.2	22256	Escondido
Total Distribution		**44.37 MW**		
Domain	**Project Name**	**Capacity / MW**	**Nearest Bus ID Number**	
Customer	SGIP/Non-SGIP Installed	14.64	Varies	Varies
Customer	SGIP/Non-SGIP In Progress	3.65	Varies	Varies
Customer	Permanent Load Shift Program	1.3	22864	Varies
Total Customer		**19.59 MW**		

Source: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M172/K519/172519400.PDF

4.9 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 4.9-1 lists the capability and power flows that will be modeled in each scenario on these paths in the northern area assessment[24].

Table 4.9-1: Major Path flows in northern area (PG&E system) assessment[25]

Path	Transfer Capability/SOL (MW)	Scenario in which Path will be stressed
Path 26 (N-S)	4000[26]	Summer Peak
PDCI (N-S)	3100	
Path 66 (N-S)	4800[27]	
Path 15 (N-S)	-5400[28]	Summer Off Peak
Path 26 (N-S)	-3000	
Path 66 (N-S)	-3675	Winter Peak

For the summer off-peak cases in the northern California study, Path 15 flow is adjusted to a level close to its rating limit of 5400 MW (S-N). This is typically done by increasing the import on Path 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, Table 4.9-2 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.

[24] These path flows will be modeled in all base cases.
[25] 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)
[26] May not be achievable under certain system loading conditions.
[27] The Path 66 flows will be modeled to the applicable seasonal nomogram for the base case relative to the northern California hydro dispatch.
[28] May not be achievable under certain system loading conditions

Table 4.9-2: Major Path flows in southern area (SCE and SDG&E system) assessment

Path	Transfer Capability/SOL (MW)	Near-Term Target Flows (MW)	Scenario in which Path will be stressed, if applicable
Path 26 (N-S)	4,000	4,000	Summer Peak
PDCI (N-S)	3220	3220	
West of River (WOR)	11,200	5,000 to 11,200	N/A
East of River (EOR)	10,100	4,000 to 9,600	N/A
San Diego Import	2,850	2,400 to 3,500	Summer Peak
SCIT	17,870	15,000 to 17,870	Summer Peak
Path 45 (N-S)	400	0 to 250	Summer Peak
Path 45 (S-N)	800	0 to 300	Off Peak

4.10 Operating Procedures

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

Please refer to http://www.caiso.com/thegrid/operations/opsdoc/index.html for the list of publicly available Operating Procedures.

4.11 Study Scenarios

4.11.1 Base Scenarios

The main study scenarios cover critical system conditions driven by several factors such as:

<u>Generation:</u>

Existing and future generation resources are modeled and dispatched to reliably operate the system under stressed system conditions. More details regarding generation modeling is provided in section 4.7.

<u>Demand Level:</u>

Since most of the ISO footprint is a summer peaking area, summer peak conditions will be evaluated in all study areas. However, 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 4.11-1 lists the scenarios that will be conducted in this planning cycle.

<u>Path flows:</u>

For local area studies, transfers on import and monitored internal paths will be modeled as required to serve load in conjunction with internal generation resources. For bulk system studies, major import and internal transfer paths will be stressed as described in Section 4.9 to assess their FAC-013-2 Transfer Capability or FAC-014-2 System Operating Limits (SOL) for the planning horizon, as applicable.

The base scenarios for the reliability analysis are provided in Table 4.11-1

Table 4.11-1: Summary of Study Base Scenarios in the ISO Reliability Assessment

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2019	2022	2027
Northern California (PG&E) Bulk System	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak Summer Partial Peak Spring Off-Peak
Humboldt	Summer Peak Winter Peak Spring Light Load	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak Winter peak Spring Light Load	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter peak
North Valley	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Central Valley (Sacramento, Sierra, Stockton)	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Greater Bay Area	Summer Peak Winter peak - (SF & Peninsula) Spring Light Load	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF Only)
Greater Fresno	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Kern	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Central Coast & Los Padres	Summer Peak Winter Peak Spring Light Load	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
Southern California Bulk transmission system	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE Metro Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE Northern Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE North of Lugo Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE East of Lugo Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE Eastern Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SDG&E main transmission	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak

SDG&E sub-transmission	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Valley Electric Association	Summer/Winter Peak Spring Light Load	Summer/Winter Peak Spring Off-Peak	Summer/Winter Peak

Note: - Peak load conditions are the peak load in the area of study. Peak load time - hours between 16:00 and 18:00.
- Off-peak load conditions are approximately 50-65 per cent of peak loading conditions. Off-peak load time – weekend morning.
- Light load conditions are the system minimum load condition. Light load time - hours between 02:00 and 04:00.
- Partial peak load condition represents a critical system condition in the region based upon loading, dispatch and facilities rating conditions. Partial peak load time - hours between 20:00 and 21:00.

4.11.2 Sensitivity Studies

In addition to the base scenarios that the ISO will be assessing in the reliability analysis for the 2017-2018 transmission planning process, the ISO will also be assessing the sensitivity scenarios identified in Table 4.11-2. The sensitivity scenarios are to assess impacts of 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 4.11-2: Summary of Study Sensitivity Scenarios in the ISO Reliability Assessment

Sensitivity Study	Near-term Planning Horizon		Long-Term Planning Horizon
	2019	2022	2027
Summer Peak with high CEC forecasted load and peak shift		PG&E Local Areas SCE Metro SCE Northern SDG&E Main SDG&E Sub-transmission	-
CEC peak-shift scenario	PG&E Local Areas SCE Metro SCE Northern SDG&E Main SDG&E Sub-transmission	-	PG&E Bulk PG&E Local Areas SCE Metro SCE Northern SDG&E Main SDG&E Sub-transmission
Off-peak with maximum PV Output		- PG&E Bulk Southern California Bulk	
Summer Peak with heavy renewable output and minimum gas generation commitment	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Northern SCE North of Lugo SCE East of Lugo SCE Eastern SCE Metro SDG&E Main	-
Summer Off-peak with heavy renewable output and minimum gas generation commitment (renewable generation addition)	-	VEA Area	-
Summer Peak with low hydro output	-	SCE Northern Area	-
Permanent closure of the Aliso Canyon gas storage facility	SCE Metro SDG&E Main		
Retirement of QF Generations	-	-	PG&E Local Areas

4.12 Study Base Cases

The power flow base cases from WECC will be used as the starting point of the ISO transmission plan base cases. Table .12-1 shows WECC base cases will be used to represent the area outside the ISO control area for each study year. For dynamic stability studies, the latest WECC Master Dynamics File (from December 18, 2015) will be used as a starting point. Dynamic load models will be added to this file.

Table 4.12-1: Summary of WECC Base Cases used to represent system outside ISO

Study Year	Season	WECC Base Case
2019	Summer Peak	18HS3Sa
	Winter Peak	17HW3b
	Spring Light	17LSP2sa
2022	Summer Peak	22HS1a
	Winter Peak	22HW2a
	Spring Off-Peak	17LSP2sa
2027	Summer Peak	26hs1a
	Winter Peak	26HW1a
	Spring Off-Peak	26LSP1Sa
	Summer Partial Peak	26hs1a

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 2022 summer peak base case for the northern California will use 2022HS1a 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.

Known outages of generation or transmission facilities with a duration of at least six months will be modeled in the base cases based on information obtained from PTOs, generation owners and other entities along with relevant data from the ISO Outage Management System (OMS).

4.13 Contingencies:

In addition to the system under normal conditions (P0), the following contingencies will be evaluated as part of the study. These contingencies lists will be made available on the ISO 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)[29][30]
- 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)[31]
- 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)

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

- Loss of a bus-tie-breaker (P4.6)

Multiple contingency (Category P5)

The assessment will consider the Category P5 contingencies with delayed fault clearing due to the failure of a non-redundant relay 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[32] (P7.1)
- Loss of a bipolar DC lines (P7.2)

Extreme contingencies (TPL-001-4)

As a part of the planning assessment the ISO assesses Extreme Event contingencies per the requirements of TPL-001-4; 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.

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

4.14 Study Tools

The 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.

4.15 Technical Studies

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

4.15.1 Steady State Contingency Analysis

The ISO will perform power flow contingency analyses based on the ISO Planning Standards[33] which are based on the NERC reliability standards and WECC regional criteria for all local areas studied in the ISO controlled grid and with select contingencies outside of the ISO controlled grid. The transmission system will be evaluated under normal system conditions NERC Category P0 (TPL 001-4), against normal ratings and normal voltage ranges, as well as emergency conditions NERC Category P1-P7 (TPL 001-4) 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)[34]. Examples of these outages are combined cycle power plants such as Delta Energy Center and Otay Mesa power plant. Such outages are studied as G-1 contingencies.

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

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

Power flow studies will be performed in accordance with PRC-023 to determine which of the facilities (transmission lines operated below 200 kV and transformers with low voltage terminals connected below 200 kV) in the Planning Coordinator Area are critical to the reliability of the Bulk

[33] California ISO Planning Standards are posted on the ISO website at http://www.caiso.com/Documents/FinalISOPlanningStandards-April12015_v2.pdf

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

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.

4.15.2 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.

4.15.3 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.

4.15.4 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.

4.15.5 Voltage Stability and Reactive Power Margin Analyses

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 ISO 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.

4.15.6 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 ISO 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.

4.16 Corrective Action Plans

Corrective action plans will be developed to address reliability concerns identified through the technical studies mentioned in the previous section. The ISO 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 ISO, 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 ISO 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 ISO might consider developing corrective action plan for deficiencies identified in sensitivity studies on a case by case basis.

5. Local Capacity Requirement Assessment

5.1 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 ISO 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 ISO "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:

- 2018 – Local Capacity Area Technical Study
- 2022 – 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 ISO will complete the LCR studies approximately by May 1, 2017.

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: ISO-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 ISO website at:

http://www.caiso.com/Documents/Local%20capacity%20requirements%20process%20-%20studies%20and%20papers

Tools: GE PSLF version 19 will be used in the LCR study.

Since LCR is part of the overall ISO Transmission Plan, the Near-Term LCR reports will be posted on the 2017-2018 ISO Transmission Planning Process webpage.

5.2 Long-Term Local Capacity Requirement Assessment

In the 2016-2017 Transmission Plan, the ISO evaluated long-term local capacity requirements (LCR) for all ten LCR areas. Based on the alignment[35] of the ISO transmission planning process with the CEC Integrated Energy Policy Report (IEPR) demand forecast and the CPUC Long-Term Procurement Plan (LTPP) proceeding, the long-term LCR assessment is to take place every two years. Based on the alignment of the CPUC LTPP and ISO TPP processes, the next comprehensive long-term LCR assessment for all ISO LCR areas will be performed in the 2018-2019 transmission planning process. However, the ISO may consider performing a long-term LCR assessment for the Moorpark subarea, and the combined LA Basin and San Diego LCR areas to assess local capacity needs based on the latest updates for potential further procurement (i.e., SDG&E 2016 RFO for preferred resources and any additional battery energy storage system projects related to Aliso Canyon gas storage constraint), updates from the CEC permitting process for the CPUC-approved conventional resources for local capacity requirement areas, and any potential changes in the progress of ISO-approved transmission projects required for Southern California reliability.

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

6. Policy Driven 33% RPS Transmission Plan Analysis

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

6.1 Public Policy Objectives

The revised TPP created a category of transmission additions and upgrades to enable the ISO 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.

Evaluating the need for policy-driven transmission elements begins in Phase 1 with the ISO'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 2017-2018 planning cycle, the overarching public policy objective continues to be the state's mandate for 33% renewable energy by 2020. For purposes of the TPP study process, this high-level objective is comprised of two sub-objectives: first, to support the delivery of 33% renewable energy over the course of all hours of the year, and second, to support Resource Adequacy (RA) deliverability status for the renewable resources outside the ISO balancing authority area that are needed to achieve the 33% energy goal. Either of these sub-objectives could lead to the identification and approval of policy-driven transmission elements in the ISO's 2017-2018 transmission plan.

The ISO and the CPUC have a memorandum of understanding under which the CPUC provides the renewable resource portfolio or portfolios for ISO to analyze in the ISO's annual TPP. As specified in the "Draft 2017 Assumptions and Scenario for Long Term Planning"[36], document a single Reliability Scenario has been included as a Planning Scenario. This scenario uses the same RPS portfolio that was supplied by Commission staff to the CAISO for the 2016-2017 TPP, the "33% 2025 Mid AAEE" trajectory portfolio. Because this portfolio is not expected to be significantly different from the 33% portfolio studies as part of the 2015-216 and 2016-2017 TPP, these resources will be studied as part of the long-term reliability assessment base cases only.

6.2 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 ISO 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:

[36] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M172/K519/172519400.PDF

- 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 October 2017, the ISO 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. The comprehensive Transmission Plan will contain the results of the ISO's evaluation of the identified Network Upgrades. Network Upgrades evaluated by the ISO 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 ISO 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 ISO protected web-site for stakeholder review. Study results and recommendations from these cases will be incorporated in the comprehensive transmission plan.

Transmission Planning Deliverability

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

7. Special Studies

In the 2016-2017 planning cycle, the ISO undertook a significant number of special studies that, while not forming the basis for transmission solutions or development, provided insights into future planning efforts. A number of these efforts require further analysis or coordination with other planning regions or agencies, and that work will be completed within the next calendar year as set out below – either on a parallel study track or as a continuation of the 2016-2017 planning cycle. These efforts have also identified issues that should be resolved and addressed before further studies are undertaken.

On that basis, the ISO is not proposing any new special studies in the 2017-2018 planning cycle. The status of the studies undertaken in the 2016-2017 planning cycle that require continued effort to complete are discussed below.

7.1 50% Renewable Energy Goal for 2030

During the 2016-2017 planning cycle the ISO undertook a special study to provide information regarding the potential need for public policy-driven transmission additions or upgrades to support a state 50% renewable energy goal. This study considered both in-state scenarios as well as scenarios that relied on a material amount of out-of-state resources. The out-of-state scenario analysis also formed the basis of the ISO's coordination with the other western planning regions in conducting interregional planning coordination under our respective FERC Order No.1000 planning processes.

The ISO performed this study for informational purposes only; its results were not used to support a need for policy-driven transmission. The interregional portion of the analysis is still ongoing. This work will be completed as a continuation of the 2016-2017 planning cycle, rather than restarting the work as part of a new special study.

7.2 Frequency Response Assessment

In the 2014-2015 and 2015-2016 transmission planning process the ISO conducted initial studies into frequency response and headroom requirements for potential over-supply conditions. The study results indicated acceptable frequency performance within WECC; however the ISO's frequency response may fall below the ISO frequency response obligation specified in NERC reliability standard BAL-003-1. Compared to the ISO's actual system performance during disturbances, the study results seem optimistic because actual frequency responses for some contingencies were lower than the dynamic model indicated. Further model validation was found to be needed to ensure that governor response in the simulations aligns with the actual response on the system. In the 2017-2018 TPP the ISO will assess the validation of models based on real-time contingencies and work with the facility owners to update the models as required. The ISO will provide updates on the progress of this assessment through the 2017-2018 transmission planning process.

7.3 Gas-Electric Reliability

The potential impacts of the changing role of gas-fired generation in providing local capacity support and flexible generation needs has been raised as a concern regarding both physical capacity and gas contracting requirements that should be examined in the planning framework. In the 2015-2016 and the 2016-2017 planning cycles, the ISO explored and performed preliminary transmission planning related studies focused on gas supply scenarios. Going forward, the ISO plans to participate in upcoming regulatory proceedings on the Aliso Canyon Gas Storage Facility.

7.4 Economic Early Retirement of Gas Generation Assessment

There is a potential for the economic early retirement of gas generation as a result of the increasing levels of renewable generation interconnecting to the electrical grid. In the 2016-2017 planning cycle a special study was performed to develop and assess early retirement scenarios to identify if there are any reliability impacts associated with the early retirement of gas generation on the ISO controlled grid. It is expected that some aspects of this work will continue into the 2017-2018 planning cycle.

7.5 Characteristics of Slow Response Local Capacity Resources

In order to be effective, local capacity resources either need to be capable of assisting the system in preparing for a second contingency within 30 minutes of an initial contingency, or being sufficiently unconstrained that the resources may be dispatched whenever certain loading conditions exist and in anticipation of the first contingency actually occurring – allowing a "slower" response time in responding to a dispatch. The number of dispatches in the latter case is anticipated to be orders of magnitude higher than in the former case.

The ISO has studied on a case by case basis other "fast" resources and their necessary characteristics, and has a foundational methodology[37] for those studies. In the 2016-2017 planning cycle, the ISO performed a preliminary special study to identify the characteristics of the "slower" response that are to be considered for local capacity resources. This work is expected to continue on a parallel track, and progress will be reported to stakeholders in the 2017-2018 planning cycle.

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

8. Economic Planning Study

The ISO 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 ISO ratepayers based on Transmission Economic Assessment Methodology (TEAM). Production simulation is the main tool for this study.

The Economic Planning Study will be 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 2027 (the 10^{th} planning year) through production simulation, and for year 2022 (the 5^{th} planning year) as optional, which is needed for providing a data point in the benefit assessment for transmission project economic justification.

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

In evaluation of the congestion and review of the study requests, the ISO will determine the high priority studies to be conducted during the 2017-2018 transmission planning cycle.

9. Long-Term Congestion Revenue Rights (LT CRR)

The ISO is obligated to ensure the continuing feasibility of Long Term CRRs (LT-CRRs) that are allocated by the ISO over the length of their terms. As such, the ISO, 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 ISO 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 ISO 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 ISO, 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 ISO tariff.

10. Interregional Transmission Projects

At the beginning of the 2017-2018 planning cycle the ISO will initiate a submission period in which proponents may request the ISO and at least one other planning region to evaluate an interregional transmission project (ITP). The submission period will begin January 1 and close March 31st of every even-numbered year. Following a screening process, the ISO will post an addendum to the transmission planning process final study plan outlining the projects that will be assessed for that planning cycle and the projects that were submitted but deemed as not meeting the screening criteria. The ISO along with the relevant planning region(s) will develop and post an ITP evaluation process plan, including agreed to common study assumptions, data, methodologies, cost assumptions and a schedule for determining the selection of an ITP. There will be ongoing coordination between the relevant planning regions on the planning data and assumptions, including the potential ITP benefits up until the final determination of whether or not an ITP should be included in the ISO's transmission plan.

Throughout the coordination process with the other relevant planning regions, The ISO will seek to resolve any differences it has with the other relevant planning regions relating to the ITP or to information specific to other relevant planning regions that may affect the ISO's evaluation of the ITP. Using the ISO's established economic assessment methodology, an estimate of the benefits and ISO share of the costs of the ITP to consider and compare the benefits and costs of the regional transmission solution and the estimated ISO benefits and ISO costs of the interregional transmission project which eliminates or defers a regional need. If the interregional transmission project could potentially meet a regional need more cost-effectively and efficiently than a regional transmission solution. Based on the ISO's initial assessment of ITP benefits, the ISO will determine whether to further evaluate the project during the next planning cycle. If at any time during an ITP evaluation process the ISO determines that the interregional transmission project will not meet any of its regional transmission needs, the ISO will notify the other relevant planning regions(s) and ISO stakeholders at one of the regularly scheduled stakeholder meetings shown in Table 2-1. After and ITP is determined to not be needed, the ISO has no further obligation to participate in the joint evaluation of the interregional transmission project.

11. 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 ISO Transmission Plan-related Stakeholder meetings, stakeholders may contact these individuals directly for any further questions or clarifications.

Table 11-1: SMEs for Technical Studies in 2017-2018 Transmission Planning Process

Item/Issues	SME	Contact
Reliability Assessment in PG&E	Binaya Shrestha	bshrestha@caiso.com
Reliability Assessment in SCE	Nebiyu Yimer	nyimer@caiso.com
Reliability Assessment in SDG&E	Frank Chen	fchen@caiso.com
Reliability Assessment in VEA	Sushant Barave	sbarave@caiso.com
33% RPS Transmission Plan Analysis	Sushant Barave	sbarave@caiso.com
Near-Term Local Capacity Requirements	Catalin Micsa	cmicsa@caiso.com
Long-Term Local Capacity Requirements in SCE and SDG&E	David Le	dle@caiso.com
Economic Planning Study	Yi Zhang	yzhang@caiso.com
Long-term Congestion Revenue Rights	Bryan Fong	bfong@caiso.com
Preferred Resource and Storage Evaluation Studies	Nebiyu Yimer	nyimer@caiso.com

12. Stakeholder Comments and ISO Responses

Stakeholders are hereby requested to submit their comments to:

regionaltransmission@caiso.com

All the comments the ISO receives from stakeholders on this 2017-2018 draft study plan and ISO's responses will be posted to the following link:

http://www.caiso.com/planning/Pages/TransmissionPlanning/2017-2018TransmissionPlanningProcess.aspx

APPENDIX A: System Data

A1 Existing Generation

Table A1-1: Existing generation plants in PG&E planning area

Planning Area	Generating Plant	Maximum Capacity
PG&E - Humboldt	Humboldt Bay	166
	Kekawaka	4.9
	LP Samoa	25
	Fairhaven	17.3
	Blue Lake	12
	Humboldt Area Total	**225**
PG&E - North Coast and North Bay	Santa Fe	160
	Bear Canyon	20
	Westford Flat	30
	Western Geo	38
	Geysers 5	53
	Geysers 6	53
	Geysers 7	53
	Geysers 8	53
	Geysers 11	106
	Geysers 12	106
	Geysers 13	133
	Geysers 14	109
	Geysers 16	118
	Geysers 17	118
	Geysers 18	118
	Geysers 20	118

Planning Area	Generating Plant	Maximum Capacity
	SMUD Geo	72
	Potter Valley	11
	Geo Energy	20
	Indian Valley	3
	Sonoma Landfill	6
	Exxon	54
	Monticello	12
	North Coast and North Bay Area Total	**1564**
PG&E - North Valley	Pit River	752
	Battle Creek	17
	Cow Creek	5
	North Feather River	736
	South Feather River	123
	West Feather River	26
	Black Butte	11
	CPV	717
	Hatchet Ridge Wind	103
	QFs	353
	North Valley Area Total	**2,843**
PG&E - Central Valley	Wadham	27
	Woodland Biomass	25
	UC Davis Co-Gen	4
	Cal-Peak Vaca Dixon	49
	Wolfskill Energy Center	60
	Lambie, Creed and Goosehaven	143

Planning Area	Generating Plant	Maximum Capacity
	EnXco	60
	Solano	100
	High Winds	200
	Shiloh	300
	Bowman Power House	4
	Camp Far West (SMUD)	7
	Chicago Park Power House	40
	Chili Bar Power House	7
	Colgate Power House	294
	Deer Creek Power House	6
	Drum Power House	104
	Dutch Plat Power House	49
	El Dorado Power House	20
	Feather River Energy Center	50
	French Meadow Power House	17
	Green Leaf No. 1	73
	Green Leaf No. 2	50
	Halsey Power House	11
	Haypress Power House	15
	Hellhole Power House	1
	Middle Fork Power House	130
	Narrows Power House	66
	Newcastle Power House	14
	Oxbow Power House	6
	Ralston Power House	83

Planning Area	Generating Plant	Maximum Capacity
	Rollins Power House	12
	Spaulding Power House	17
	SPI-Lincoln	18
	Ultra Rock (Rio Bravo-Rocklin)	25
	Wise Power House	20
	Yuba City Co-Generation	49
	Yuba City Energy Center	61
	Altamont Co-Generation	7
	Camanche Power House	11
	Co-generation National POSDEF	44
	Electra Power House	101
	Flowind Wind Farms	76
	GWF Tracy Peaking Plant	192
	Ione Energy	18
	Lodi CT	25
	Lodi Stigg	57
	Pardee Power House	29
	Salt Springs Power House	42
	San Joaquin Co-Generation	55
	Simpson Paper Co-Generation	50
	Stockton Co-Generation (Air Products)	50
	Stockton Waste Water Facility	2
	Thermal Energy	21
	Tiger Creek Power House	55
	US Wind Power Farms	158

Planning Area	Generating Plant	Maximum Capacity
	West Point Power House	14
	Lodi Energy Center	280
	GWF Tracy Expansion	145
	Beardsley Power House	11
	Donnells Power House	68
	Fiberboard (Sierra Pacific)	6
	Melones Power Plant	119
	Pacific Ultra Power Chinese Station	22
	Sand Bar Power House	15
	Spring Gap Power House	7
	Stanislaus Power House	83
	Stanislaus Waste Co-gen	24
	Tullock Power House	17
	Central Valley Area Total	**3,970**
PG&E - Greater Bay Area	Alameda Gas Turbines	51
	Calpine Gilroy I	182
	Crockett Co-Generation	240
	Delta Energy Center	965
	Marsh Landing	774
	Russell City – East Shore EC	640
	High Winds, LLC	162
	Los Esteros Critical Energy Facility	362
	Los Medanos Energy Center	678
	Mariposa Peaker	200
	Metcalf Energy Center	575

Planning Area	Generating Plant	Maximum Capacity
	Oakland C Gas Turbines	165
	Donald Von Raesfeld Power Plant	164
	Pittsburg Power Plant	1,360
	Riverview Energy Center	61
	Ox Mountain	13
	Gateway Generating Station	599
	Greater Bay Area Total	**7191**
PG&E - Greater Fresno Area	Fresno Cogen-Agrico	79.9
	Adams_E	19
	Adera Solar	20
	Alpaughn_20S	20
	Alpaughn_50S	50
	Atwell	20
	Avenal	6
	Balch 1 PH	31
	Balch 2 PH	107
	Bulld 12	2.8
	Blackwell Solar	3
	Mendota Biomass Power	25
	Cantua	20
	Chow 2 Peaker Plant	52.5
	Chevron USA (Coalinga)	25
	Chow II Biomass to Energy	12.5
	CID Solar	20
	Citizen Solar B	5

Planning Area	Generating Plant	Maximum Capacity
	Coalinga Cogeneration Company	46
	CalPeak Power – Panoche LLC	49
	Crane Valley	0.9
	Corcoran PB	20
	Corcoran City	11
	Dinuba Generation Project	13.5
	El Nido Biomass to Energy	12.5
	EE Kettleman Land	20
	Exchequer Hydro	94.5
	Fresno Waste Water	9
	Friant Dam	27.3
	Fresno Solar West & South	3
	GWF Henrietta Peaker Plant	109.6
	Gates_Dist	30
	Giffen_Dist	10
	Guernsey_Dist	20
	HEP Peaker Plant Aggregate	102
	Hanford L.P.	23
	Hass PH Unit 1 &2 Aggregate	146.2
	Helms Pump-Gen	1,212
	J.R. Wood	10.8
	Jgbswlt	2.9
	Kansas	40
	Kent	20
	Kerkhoff PH1	32.8

Planning Area	Generating Plant	Maximum Capacity
	Kerkhoff PH2	142
	Kingsburg Cogen	34.5
	Kings River Hydro	51.5
	Kings River Conservation District	112
	Liberty V Lost Hills	20
	Madera	28.7
	McCall	2.5
	McSwain Hydro	10
	Merced Falls	4
	Merced Solar	1.5
	Mission Solar	1.5
	Morelos Del Sol	15
	North Star Solar 1	60
	O’Neill Pump-Gen	11
	Panoche Energy Center	410
	Pine Flat Hydro	189.9
	Quinto Solar PV	107.6
	Sanger Cogen	67.5
	Sandrag	19
	San Joaquin 2	3.2
	San Joaquin 3	4.2
	Schindler	30
	Starwood Panoche	121.8
	Stroud	20
	Stratford	20

Planning Area	Generating Plant	Maximum Capacity
	Suncity	20
	SUN Harvest Solar	1.5
	Rio Bravo Fresno (AKA Ultrapower)	26.5
	Vega Solar	20
	Wellhead Power Gates, LLC	49
	Wellhead Power Panoche, LLC	49
	Westlands	38
	Westlands Solar Farm	18
	Wishon/San Joaquin #1-A Aggregate	20.4
	2097 Helton	1.5
	Greater Fresno Area Total	**4,316**
PG&E - Kern Area	Badger Creek (PSE)	49
	Chalk Cliff	48
	Cymric Cogen (Chevron)	21
	Cadet (Chev USA)	12
	Dexzel	33
	Discovery	44
	Double C (PSE)	45
	Elk Hills	623
	Frito Lay	8
	Hi Sierra Cogen	49
	Kern	177
	Kern Canyon Power House	11
	Kernfront	49
	Kern Ridge (South Belridge)	76

Planning Area	**Generating Plant**	**Maximum Capacity**
	La Paloma Generation	926
	Midsun	25
	Mt. Poso	56
	Navy 35R	65
	Oildale Cogen	40
	Bear Mountain Cogen (PSE)	69
	Live Oak (PSE)	48
	McKittrick (PSE)	45
	Rio Bravo Hydro	11
	Shell S.E. Kern River	27
	Solar Tannenhill	18
	Sunset	225
	North Midway (Texaco)	24
	Sunrise (Texaco)	338
	Sunset (Texaco)	239
	Midset (Texaco)	42
	Lost Hills (Texaco)	9
	University Cogen	36
	New RPS Units	55
	Kern Area Total	**3,543**
PG&E - Central Coast and Los Padres	Moss Landing Power Plant	2,600
	Soledad Energy	10
	Basic Energy Cogen (King City)	133
	King City Peaker	70
	Sargent Canyon Cogen (Oilfields)	45

Planning Area	**Generating Plant**	**Maximum Capacity**
	Salinas River Cogen (Oilfields)	45
	Diablo Canyon Power Plant	2,400
	Union Oil (Tosco)	6
	Santa Maria	8
	Vandenberg Air Force Base	15
	Topaz	550
	California Valley Solar	250
	Central Coast and Los Padres Area Total	**6,132**

Table A1-2: Existing generation plants in SCE planning area

Planning Area	Generating Plant	Maximum Capacity
SCE - Tehachapi and Big Creek Corridor	Big Creek 1-1 Gen 1	19.9
	Big Creek 1-1 Gen 2	21.6
	Big Creek 1-2 Gen 3	21.6
	Big Creek 1-2 Gen 4	31.2
	Big Creek 2-1 Gen 1	50.8
	Big Creek 2-1 Gen 2	52.0
	Big Creek 2-2 Gen 3	18.7
	Big Creek 2-2 Gen 4	19.7
	Big Creek 2-3 Gen 5	17.0
	Big Creek 2-3 Gen 6	18.5
	Big Creek 3-1 Gen 1	35.0
	Big Creek 3-1 Gen 2	35.0
	Big Creek 3-2 Gen 3	35.0
	Big Creek 3-2 Gen 4	41.0
	Big Creek 3-3 Gen 5	39.0
	Big Creek 4 Gen 41	50.4
	Big Creek 4 Gen 41	50.6
	Big Creek 8 Gen 81	24.4
	Big Creek 8 Gen 81	44.0
	Eastwood	207.0
	Mamoth 1G	93.5
	Mamoth 2G	93.5
	Portal	9.6
	Warne 1	38.0

Planning Area	Generating Plant	Maximum Capacity
	Warne 2	38.0
	Pandol 1	56.0
	Pandol 2	56.0
	Ultragen	41.0
	Omar 1G	90.8
	Omar 2G	90.8
	Omar 3G	90.8
	Omar 4G	90.8
	SYCCYN 1G	75.0
	SYCCYN 2G	75.0
	SYCCYN 3G	75.0
	SYCCYN 4G	75.0
	Pastoria Energy Facility	770.0
	Manzana Wind Project	189.0
	Pacific Wind Project	140.0
	Coram Brodie Wind Project Expansion	51.0
	Coram Brodie Wind Project Phase 2	51.0
	Alta 2012	720.0
	CPC Alta Wind 4-5 (fka CPC East)	420.0
	CPC Alta Wind 1-3 (fka CPC West)	600.0
	Windstar I Alternate	120.0
	Eastwind	60.0
	Westwind	21.0
	Tehachap	114.4
	WNDT167	120.0

Planning Area	Generating Plant	Maximum Capacity
	North Sky River Wind	170.0
	Sky River	76.9
	Catalina Solar	150.0
	KR 3-1	22.8
	KR 3-2	21.5
	LakeGen	18.0
	Wellhead Power Delano	49.9
	Kawgen	18.0
	Avenue	310.0
	Kingsbird	270.0
	AV Solar 1	249.0
	Arbwind	21.8
	Canwind	65.0
	Enwind	47.1
	Encawind	112.9
	Flowind	40.8
	Dutchwind	14.0
	Northwind	19.4
	Oakwind	21.1
	Southwind	13.4
	Zondwind	26.0
	Breeze	12.5
	Midwind	18.0
	Morwind	56.0
	Kern River	24.0

Planning Area	Generating Plant	Maximum Capacity
	Borel	10.0
	Alta Vista Suntower Generating Station	66.0
	Antelope Power Plant	20.0
	Down	20.0
	Twilight	20.0
	Antelope Valley PV1	318.5
	Antelope Valley PV2	285.0
	Rising Tree	198.8
	Western Antelope Blue Sky Ranch A	20.0
	First Solar North Rosamond	100.8
	AV Solar Ranch 2-A	20.4
	AV Solar Ranch 2-B	20.4
	RE Astoria	181.1
	RE Camelot	45.0
	RE Columbia	15.0
	TA Acacia	20.0
	SGS Antelope Valley	300.0
	North Rosamond	156.2
	Tehachapi and Big Creek Corridor Total	**8,410.9**
SCE - East of Lugo Area	Desert Star Energy Star	506
	Mountain Pass - Ivanpah Solar	392
	Copper Mountain Solar I	58
	Copper Mountain Solar II	155
	East of Lugo Area Total	**1,111**

Planning Area	Generating Plant	Maximum Capacity
SCE - North of Lugo	ALBAG1	140
	BLM E7G	24
	BLM E8G	24
	BLM W9G	19.5
	BORAX I	22
	BSPHYD26	14.18
	BSPHYD34	15.9
	BLM E7G	24
	CALGEN	92.2
	CSA DIABLO 1	15
	CSA DIABLO 2	10
	High Desert Power Plant	854.9
	KERRMGEE	15
	LUNDY	3
	LUZ (8 & 9)	160
	NAVYII4G	22.5
	NAVYII5G	22.5
	NAVYII6G	22.5
	OCASOG2	140
	OXBOW G1	49.8
	POOLE	10.9
	RUSH	11.5
	SEGS 1G	14.2
	SEGS 2G	43.8

Planning Area	Generating Plant	Maximum Capacity
	SUNGEN	150
	North of Lugo Area Total	**1,897**
SCE - Eastern Area	Blythe Energy Center	520
	Indigo Peaker	136
	Cabazon Wind	42.6
	Mountainview IV Wind	42
	Wintec 5 Wind	3.7
	Wintec 6 Wind	45
	Pacificorp Wind	2.1
	FPLE Green 1 Wind	8.7
	FPLE Green 2 Wind	3.0
	FPLE Green 3 Wind	6.8
	Wintec 2 Wind	16.5
	Wintec 3 Wind	11.6
	Wintec 4 Wind	16.5
	Seawest 1 Wind	44.4
	Seawest 2 Wind	22.2
	Seawest 3 Wind	22.4
	Renwind Wind	9.0
	Whitewater Wind	66
	Altamesa 4 Wind	40
	Painted Hills Wind	16.9
	Altwind QF 1	32.9
	Altwind QF 2	15.1
	Buchwind QF	17

Planning Area	Generating Plant	Maximum Capacity
	Capwind QF	20
	Garnet QF Wind	101.4
	Panaero Wind	30
	Renwind QF 1	6.3
	Renwind QF 2	6.6
	Sanwind QF 1	3.0
	Sanwind QF 2	28.0
	Seawind QF	27
	Terawind QF	22.5
	Transwind QF	40.0
	Venwind QF 1	25.5
	Venwind QF 2	19.3
	CPV Sentinel Peaker	850
	Genesis Solar Energy Project	250
	Desert Sunlight PV Project	550
	McCoy Photovoltaic Project[38]	126.16
	Windustries	9.8
	Edom Hills Wind Farm	20
	Karen Avenue Wind Farm	11.7
	Eastern Area Total	**3,287.66**
SCE Metro Area	Agua Mansa Generating Facility	43
	Alamitos	2,010
	Anaheim CT	41
	AP North Lake Solar	20

[38] This project is partially operational at 126.16 MW, with a total capacity of 250 MW

Planning Area	Generating Plant	Maximum Capacity
	Barre Peaker	45
	Berry Petroleum Placerita	37
	BP West Coast Products	21
	Broadway 3	65
	Calabasas Gas-to-Energy Facility	7
	Canyon Power Plant	195
	Carson Cogeneration Company	47
	Center Area Lumped Units	18
	Center Peaker	45
	Century	36
	Chevron CIC	170.7
	Chiquita Canyon Landfill Generating Facility	7
	City Of Long Beach	28
	Clearwater Power Plant	28
	Corona Energy Partners, Ltd.	30
	County Of Los Angeles (Pitchess Honor Ranch)	19
	Coyote Canyon	6
	Devil Canyon	235
	Drews	36
	E. F. Oxnard, Incorporated	34
	El Segundo 4	335
	El Segundo Energy Center	570
	Ellwood Generating Station	54
	Etiwanda 3 & 4	640

Planning Area	Generating Plant	Maximum Capacity
	Etiwanda Hydro Recovery Plant	10
	Foothill Hydro Recovery Plant	8
	Glen Arm Power Plant	132
	Grapeland Peaker	43
	H. Gonzales Gas Turbine	12
	Harbor Cogen Combined Cycle	100
	Houweling Nurseries Oxnard CHP	13.2
	Huntington Beach 1 & 2	452
	Inland Empire Energy Center	670
	L.A. County Sanitation District #2 (Puente Hills B)	47
	Long Beach 1 – 4	260
	Malburg Generating Facility	134
	Mandalay 1 & 2	430
	Mandalay 3 GT	130
	Mira Loma Peaker	43
	MM West Coast Covina, LLC	6
	Mojave Siphon PH	18
	Mountainview Power Plant	969
	MWD Perris Hydroelectric Recovery Plant	8
	O.L.S. Energy Company- Chino-Mens Inst.	25
	Ormond Beach	1,516
	Procter & Gamble Paper Prod. (Oxnard II)	46
	Redondo	1,356
	Ripon Cogeneration	27

Planning Area	Generating Plant	Maximum Capacity
	Riverside Energy Resource Center (RERC)	194
	San Dimas Hydro Recovery Plant	8
	Springs Generation Plant	36
	SPVP044	8
	Sunshine Gas Producers, L.L.C.	20
	Tequesquite Landfill Solar Project	7.5
	Walnut Creek Energy Park	500
	Watson Cogeneration	406
	Weyerhaeuser Company (Formerly Williamette Industries)	13
	Multiple smaller facilities	85.5
	Metro Area Total	**12,556**

Table A1-3: Existing generation plants in SDG&E planning area

Planning Area	Generating Plant	Maximum Capacity
SDG&E	Otay Mesa GT1	185.1
	Otay Mesa GT2	185.1
	Otay Mesa ST1	233.5
	Larkspur Border 1	46.0
	Larkspur Border 2	46.0
	Cabrillo	3.1
	Capistrano	5.3
	Carlton Hills	1.6
	Carlton Hills	0.3
	Chicarita	3.7
	Border/Calpeak	48.0
	El Cajon/Calpeak	45.4
	Escondido/Calpeak	48.0
	DIVSON_6_NSQF	41.7
	East Gate	0.3
	Encina 1	106.0
	Encina 2	104.0
	Encina 3	110.0
	Encina 5	300.0
	Encina 4	330.0
	Encina GT	14.5
	MMC-Electrovest (Escondido)	49.5

Planning Area	Generating Plant	Maximum Capacity
	Palomar_CT1	162.4
	Palomar_CT2	162.4
	Palomar_ST	240.8
	Goalline	38.4
	Mesa Heights	3.6
	Miramar 1	48.0
	Miramar 2	47.9
	Mission	0.7
	North Island	36.4
	Otay Landfill I	2.8
	Otay Landfill II	2.6
	Covanta Otay 3	3.5
	MMC-Electrovest (Otay)	35.5
	Orange Grove 1	50.0
	Orange Grove 2	50.0
	NTC Point Loma Steam turbine	2.0
	NTC Point Loma	19.4
	Sampson	1.0
	San Marcos Landfill	0.7
	El Cajon Energy Center	48.1
	Lake Hodges Pumped Storage 1	20.0
	Lake Hodges Pumped Storage 2	20.0
	BREGGO SOLAR (NQC)	26.0

Planning Area	Generating Plant	Maximum Capacity
	Kumeyaay	50.0
	East County	155.0
	Ocotillo Express	265.0
	KEARNGT1	16.0
	KEARN2AB	15.0
	KEARN2AB	15.0
	KEARN2CD	15.0
	KEARN2CD	14.0
	KEARN3AB	15.0
	KEARN3AB	16.1
	KEARN3CD	15.0
	KEARN3CD	15.0
	Miramar GT 1	17.0
	Miramar GT 2	16.0
	Naval Station	47.0
	El Cajon GT	13.0
	Ash	0.9
	Rancho Santa Fe 1	0.4
	Rancho Santa Fe 2	0.3
	Murray	0.2
	Kyocera	0.1
	SDG&E Area Total	**3,630**

Table A1-4: Existing generation plants in VEA planning area

Planning Area	Generating Plant	Maximum Capacity
VEA	Not Applicable	0
	VEA Area Total	**0**

A2 Planned Generation

Table A2-1: Planned Generation – Thermal and Solar Thermal

PTO Area	Project	Capacity (MW)	First Year to be Modeled
PG&E	-	-	-
SCE	Huntington Beach Energy Project Unit 6 (CCGT) *	644	2020
	Alamitos Energy Center Unit 8 (CCGT) *	640	2020
	Stanton Energy Center*	98	2020
	Puente Power Project*	262	2020
SDG&E	Carlsbad Peakers*	500	2019

Notes:

*These projects have received PPTA approvals from the CPUC as part of Long Term Procurement Plan (LTPP) process.

A3 Retired Generation

Table A3-1: Generation (non-OTC) projected to be retired in planning horizon[39]

PTO Area	Project	Capacity (MW)	First Year to be retired
PG&E	Pittsburg Unit 7	682	2017
SCE	Coolwater Units 1, 2, 3 & 4	636	2015
SDG&E	Kearny Peakers	135	2017
	Miramar GT1 and GT2	36	2017
	El Cajon GT	16	2017

Table A3-2: list of generators in SCE, SDG&E and PG&E areas that will be older than 40 years by 2027

Generating Unit Name / Description	Nameplate Capacity (MW)	COD
SCE Area		
AltaGas Pomona Energy Inc.	44.0	11/18/1985
BP WILMINGTON CALCINER	35.8	1/1/1982
ETIWANDA UNIT 3	333.0	5/1/1963
ETIWANDA UNIT 4	333.0	10/18/1963
Ellwood Generating Station	56.0	8/1/1974
Broadway 3	65.0	1/1/1965
CHEVRON U.S.A. UNIT 1	49.0	1/1/1976
Glen Arm Power Plant 1	30.6	1/1/1976
Glen Arm Power Plant 2	30.6	1/1/1976
MOORE PARK AREA LUMPED UNITS	30.0	1/1/1976
Coolwater Unit 1	65.0	1/1/1961
Coolwater Unit 2	71.0	1/1/1964
KERN RIVER COGENERATION UNIT 1	85.0	5/1/1985
KERN RIVER COGENERATION UNIT 2	85.0	5/1/1985
KERN RIVER COGENERATION UNIT 3	85.0	5/1/1985
KERN RIVER COGENERATION UNIT 4	85.0	5/1/1985

[39] Table A3-1 reflects retirement of generation based upon announcements from the generators. The ISO will document generators assumed to be retired as a result of assumptions identified in Section 4.9 as a part of the base case development with the reliability results.

Generating Unit Name / Description	Nameplate Capacity (MW)	COD
Mandalay 3 GT	130.0	4/1/1970
New-Indy Ontario, LLC	36.6	9/1/1985
New-Indy Oxnard LLC	27.8	3/14/1986
SEARLES VALLEY MINERALS OPERATIONS, INC. (ARGUS)	62.5	4/1/1983
U.S. BORAX AND CHEMICAL CORP. (#1)	22.0	6/1/1984
MOBIL OIL CORPORATION #1	41.9	5/1/1983
Long Beach (Units 1-4)	260.0	8/1/2007 (refurbish date)
SDG&E Area		
El Cajon GT	15.0	1/1/1968
Encina GT 1	18.0	1/1/1968
KEARNY KY3 (AGGREGATE)	61.0	1/1/1969
MIRAMAR GT PLANT (AGGREGATE)	36.0	1/1/1972
PG&E Area		
Alameda GT Unit 1	25.4	1/1/1986
Alameda GT Unit 2	25.4	1/1/1986
BERRY COGEN 38	37.2	1/1/1986
BERRY PETROLEUM COGEN 18	6.0	1/1/1986
CHEVRON USA (COALINGA)	19.0	1/17/1986
CHEVRON USA (CYMRIC)	24.3	10/15/1982
CHEVRON USA (TAFT/CADET)	11.5	7/26/1982
CONTRA COSTA CARBON PLANT	20.0	1/1/1983
Gianera GT 2	24.8	1/1/1986
LODI GAS TURBINE	25.4	1/1/1986
OILDALE ENERGY	47.5	12/29/1984
Oakland GT #1	74.5	1/1/1978
Oakland GT #2	74.5	1/1/1978
Oakland GT #3	74.5	1/1/1978
Pittsburg Unit 7	712.0	1/1/1972
South Belridge Cogen Facility	69.6	1/1/1985
IBM COTTLE	50.0	1/1/1984

Table A3-3: Potential OTC Generating Unit Early Retirement to Accommodate CPUC-Approved Repowering Projects (for PPTAs) in planning horizon

Southland Retirement Schedule

ALAMITOS	**MW**	**Retirement Date**
Alamitos Unit 1	175	12/31/19
Alamitos Unit 2	175	12/31/19
Alamitos Unit 3	320	12/31/20
Alamitos Unit 4	320	12/31/20
Alamitos Unit 5	480	12/31/19
Alamitos Unit 6	480	12/31/20

HUNTINGTON BEACH		
Huntington Beach Unit 1	215	10/31/19
Huntington Beach Unit 2	215	12/31/20
REDONDO BEACH		
Redondo Beach Unit 5	175	12/31/20
Redondo Beach Unit 6	175	12/31/20
Redondo Beach Unit 7	480	10/31/19
Redondo Beach Unit 8	480	12/31/20
SYNCHRONOUS CONDENSERS	**MVAR**	
Unit 3	145	12/31/16
Unit 4	145	12/31/17

A4 Reactive Resources

Table A4-1: Summary of key existing reactive resources modeled in ISO reliability assessments

Substation	Capacity (Mvar)
Gates	225
Los Banos	225
Gregg	150
McCall	132
Mesa	100
Metcalf	350
Olinda	200
Table Mountain	454
Devers	156 & 605 (dynamic capability)
Sunrise San Luis Rey	63
Southbay / Bay Boulevard	100
Miraloma	158
Suncrest	126
Penasquitos	126

A5 Special Protection Schemes

Table A5-1: Existing key Special Protection Schemes in the PG&E area

PTO	Area	SPS Name
PG&E	Los Padres	Mesa and Santa Maria Undervoltage SPS
	Los Padres	Divide Undervoltage SPS
	Los Padres	Temblor-San Luis Obispo 115 kV Overload Scheme
	Bulk	COI RAS
	Bulk	Colusa SPS
	Bulk	Diablo Canyon SPS
	Bulk	Gates 500/230 kV Bank #11 SPS
	Bulk	Midway 500/230 kV Transformer Overload SPS
	Bulk	Path 15 IRAS
	Bulk	Path 26 RAS North to South
	Bulk	Path 26 RAS South to North
	Bulk	Table Mt 500/230 kV Bank #1 SPS
	Central Valley	Drum (Sierra Pacific) Overload Scheme (Path 24)
	Central Valley	Stanislaus – Manteca 115 kV Line Load Limit Scheme
	Central Valley	Vaca-Suisun 115 kV Lines Thermal Overload Scheme
	Central Valley	West Sacramento 115 kV Overload Scheme
	Central Valley	West Sacramento Double Line Outage Load Shedding SPS Scheme
	Greater Fresno Area	Ashlan SPS
	Greater Fresno Area	Atwater SPS
	Greater Fresno Area	Gates Bank 11 SPS
	Greater Fresno Area	Helms HTT RAS
	Greater Fresno Area	Helms RAS
	Greater Fresno Area	Henrietta RAS
	Greater Fresno Area	Herndon-Bullard SPS
	Greater Fresno Area	Kerckhoff 2 RAS
	Greater Fresno Area	Reedley SPS
	Greater Bay Area	Metcalf SPS
	Greater Bay Area	SF RAS
	Greater Bay Area	South of San Mateo SPS
	Greater Bay Area	Metcalf-Monta Vista 230kV OL SPS
	Greater Bay Area	San Mateo-Bay Meadows 115kV line OL
	Greater Bay Area	Moraga-Oakland J 115kV line OL RAS
	Greater Bay Area	Grant 115kV OL SPS
	Greater Bay Area	Oakland 115 kV C-X Cable OL RAS
	Greater Bay Area	Oakland 115kV D-L Cable OL RAS
	Greater Bay Area	Sobrante-Standard Oil #1 & #2-115kV line
	Greater Bay Area	Gilroy SPS
	Greater Bay Area	Transbay Cable Run Back Scheme
	Humboldt	Humboldt – Trinity 115kV Thermal Overload Scheme
	North Valley	Caribou Generation 230 kV SPS Scheme #1
	North Valley	Caribou Generation 230 kV SPS Scheme #2
	North Valley	Cascade Thermal Overload Scheme
	North Valley	Hatchet Ridge Thermal Overload Scheme
	North Valley	Coleman Thermal Overload Scheme

Table A5-2: Existing key Special Protection Schemes in SCE area

PTO	Area	SPS Name
SCE	Antelope-Bailey	Antelope-RAS
	Big Creek Corridor	Big Creek / San Joaquin Valley RAS
	North of Lugo	Bishop RAS
	North of Lugo	High Desert Power Project RAS
	North of Lugo	Kramer RAS
	Antelope-Bailey	Midway-Vincent RAS
	Antelope-Bailey	Lancaster N-2 Line Loss Tripping Scheme
	Antelope-Bailey	Palmdale N-2 Line Loss Tripping Scheme
	Antelope-Bailey	Pastoria Energy Facility Existing RAS
	North of Lugo	Reliant Energy Cool Water Stability Tripping Scheme
	Eastern Area	West-of-Devers Remedial Action Scheme
	Eastern Area	Blythe Energy RAS
	Eastern Area	Eagle Mountain Thermal Overload Scheme
	Metro Area	El Nido N-2 Remedial Action Scheme
	Metro Area	Mountain view Power Project Remedial Action Scheme
	Metro Area	South of Lugo N-2 Remedial Action Scheme
	Metro Area	Mira Loma Low Voltage Load Shedding
	Metro Area	Santiago N-2 Remedial Action Scheme
	Metro Area	Valley Direct Load Trip Remedial Action Scheme
	Metro Area	El Segundo N-2 Remedial Action Scheme

Table A5-3: 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 CFE)
	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 SPS
	SDG&E	Path 44 South of SONGS Safety Net