2014-2015 Transmission Planning Process Unified Planning Assumptions and Study Plan

February 20, 2014

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Table of Contents

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 2014-2015 comprehensive transmission plan at the end of Phase 2.

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 2013 IEPR (approved in January 2014). The ISO has incorporated the planning assumptions and scenarios recommended by the CPUC, the CEC and the ISO and presented to stakeholders at the December 18, 2013 workshop in CPUC Docket R.13-12-010 into the proposed base cases in this draft study plan. With this draft study plan, the base planning assumptions for the 2014-2015 TPP and the 2014-2015 LTPP are effectively aligned for the 2014-2024 planning horizon proposed to be used transmission and procurement requirements.

2. Overview of 2014-2015 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 2014-2015 transmission planning cycle is provided in Table 2-1. Should this schedule change or other aspects of the 2014-2015 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://caiso.com/1c67/1c678de462d10.html and submit the Market Notice Subscription Form.

Table 2-1: Schedule for the 2014-2015 planning cycle

Phase	No	Due Date	2014-2015 Activity
Phase 1	1	December 16, 2013	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.
	3	January 16, 2014	PTO's, neighboring balancing authorities, regional/sub-regional planning groups and stakeholders provide ISO the information requested No.1 above.
	5	February 20, 2014	The ISO develops the draft Study Plan and posts it on its website
	6	February 27, 2014	The ISO hosts public stakeholder meeting #1 to discuss the contents in the Study Plan with stakeholders
	7	February 27 - March 13, 2014	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
	8	March 31, 2014	The ISO specifies a provisional list of high priority economic planning studies, finalizes the Study Plan and posts it on the public website
	9	Q1	ISO Initiates the development of the Conceptual Statewide Plan
Phase 2	10	August 15, 2014	Request Window opens
	11	August 15, 2014	The ISO posts preliminary reliability study results and mitigation solutions
	12	September 15, 2014	PTO's submit reliability projects to the ISO
	13	September 15	ISO posts the Conceptual Statewide Plan on its website and issues a market notice announcing the posting
	14	September 24 – 25, 2014	The ISO hosts public stakeholder meeting #2 to discuss the reliability study results, PTO's reliability projects, and the Conceptual Statewide Plan with stakeholders
	15	September 25 – October 9, 2014	Comment period for stakeholders to submit comments on the public stakeholder meeting #2 material
	16	October 15, 2014	Request Window closes
	17	October 20, 2014	Stakeholders have a 20 day period to submit comments on the Conceptual Statewide Plan in the next calendar month after posting conceptual statewide plan (i.e. August or September)
	18	October 30, 2014	ISO post final reliability study results

Phase	No	Due Date	2014-2015 Activity
	19	November 17, 2014	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.
	20	November 19 - 20, 2014	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.
	21	November 20 – December 4, 2014	Comment period for stakeholders to submit comments on the public stakeholder meeting #3 material
	22	December 18 – 19, 2014	The ISO to brief the Board of Governors of projects less than $50 million to be approved by ISO Executive
	23	January 2015	The ISO posts the draft Transmission Plan on the public website
	24	February 2015	The ISO hosts public stakeholder meeting #4 to discuss the transmission project approval recommendations, identified transmission elements, and the content of the Transmission Plan
	25	Approximately three weeks following the public stakeholder meeting #4	Comment period for stakeholders to submit comments on the public stakeholder meeting #4 material
	26	March 2015	The ISO finalizes the comprehensive Transmission Plan and presents it to the ISO Board of Governors for approval
	27	End of March, 2015	ISO posts the Final Board-approved comprehensive Transmission Plan on its site
Phase 3	28[1]	April 1, 2015	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

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

2.2 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 and will provide responses to these comments no later than the posting of the draft transmission plan.

2.3 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 2014-2015 transmission planning cycle is the "Transmission Planning" section located at http://www.caiso.com/1f42/1f42d6e628ce0.html 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://caiso.com/1f42/1f42d6e628ce0.html under the *Accessing transmission data* heading.

3. Public Policy Objectives and the Conceptual Statewide Transmission Plan

With FERC's approval of the ISO's revised TPP in December 2010, two important new elements were incorporated into phase 1 of the TPP. These two new elements – the specification of public policy objectives for transmission planning, and the development of a conceptual statewide plan as an input for consideration in developing the ISO's comprehensive transmission plan – are discussed in this section.

3.1 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 2014-2015 planning cycle, the overarching public policy objective is 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 2014-2015 comprehensive transmission plan.

3.1.1 Achieving 33% renewable energy on an annual basis

The state's mandate for 33% renewable energy by 2020 refers to the share of total electricity consumed by California consumers over the course of a year that is provided by renewable resources. In the context of the transmission planning studies, the question to be investigated is whether a specified portfolio of renewable supply resources, in conjunction with the conventional resource fleet expected to be operating, will deliver a mix of energy over all 8760 hours of the year that is at least 33% supplied by the renewable portfolio on an annual basis. Through the studies the ISO performs to address this question, the ISO could identify policy-driven transmission additions or upgrades that are necessary in order to achieve the 33% renewable share of annual consumption by 2020.

3.1.2 Supporting RA deliverability status for needed renewable resources outside the ISO balancing authority area

Deliverability for the purpose of a resource providing RA capacity is a distinct requirement and is integral to achieving the 33% RPS policy goal. Resources that are connected directly to the ISO grid can establish deliverability through the ISO's annual process to determine Net Qualifying Capacity (NQC) for each resource for the upcoming RA compliance year (i.e., calendar year). A new resource seeking to interconnect to the ISO grid can elect Full Capacity deliverability status in its interconnection request, and this election triggers a study process to identify any network upgrades needed for deliverability and ultimately leads to the construction of the needed network upgrades by the relevant PTO whose system needs to be upgraded.

For resources outside the ISO, however, there is no way under the current rules for the resource to obtain RA deliverability status. Rather, in conjunction with the annual NQC process the ISO assesses the Maximum Import Capability (MIC) at each intertie, and then conducts a multi-step process whereby load-serving entities inside the ISO can utilize shares of the MIC to procure external capacity to meet their RA requirements. Moreover, the determination of the intertie MIC values is based not on an assessment of maximum physical import capability in each area, but only on historic energy schedules under high-load system conditions. This approach has resulted in extremely small values for certain interties. As a result, areas outside the ISO that are rich in renewable energy potential and have been included in the ISO's 33% supply portfolios, have raised concerns that they will be unable to develop their projects if they are unable to offer RA capacity to their potential LSE buyers. The ISO therefore will include, in this TPP cycle, the policy objective of expanding RA import capability in those areas outside the ISO BAA where (a) renewable resources are needed in the 33% RPS base case portfolio[2] to meet the state's 33% RPS target, and (b) the RA import capability under the current MIC rules is not sufficient to enable these resources to provide RA capacity.

This particular sub-objective requires a different study approach than that required for the previous sub-objective. The fundamental concept behind RA is that the ISO should be able to utilize all the designated RA capacity simultaneously to provide energy and reserve capacity when needed to meet peak system demand. Pursuant to this concept, the assessment of deliverability focuses on the simultaneous operation of available internal RA capacity and import of external RA energy by designated RA capacity during system peak hours. Because this type of study is different than the studies needed for the previous sub-objective, the RA deliverability assessment could result in the ISO identifying different needed policy-driven transmission elements.

3.2 Conceptual Statewide Transmission Plan

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. The ISO incorporated an annual conceptual statewide transmission plan into its revised TPP proposal in conjunction with the provision for

[2] Further discussion of the development of 33% RPS supply portfolios is provided in section 3.3 of this paper

public policy-driven transmission, based on the recognition that public policies such as the 33% RPS, which could necessitate the development of new transmission infrastructure, might not apply to the ISO Controlled Grid alone, but could apply to the entire state (or possibly an even broader geographic region). For this reason, although the ISO's responsibility is to plan and approve transmission projects for the ISO Controlled Grid, a statewide perspective, in collaboration with other California transmission providers if possible, on how to develop needed new transmission to most efficiently meet the statewide 33% RPS mandate would clearly be a valuable input into the ISO's TPP. At the same time, although such a plan would be useful in providing a broad geographic view of needed transmission development, the plan would 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.

During the 2014-2015 TPP cycle the ISO will seek to continue to work with the California Transmission Planning Group (CTPG) to coordinate with CTPG members as to their plans within their respective areas. While the CTPG has put further analytical studies on hold as the various regions establish their new roles and procedures to comply with FERC Order 1000 regional and interregional obligations, the ISO is optimistic that CTPG will continue to play an important role in the coordination and sharing of planning activities being conducted by members of the various planning regions inside California.

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 4.1.1-4.1.16. 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 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 4-1 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 (which includes Sierra, Sacramento, and Stockton divisions);
  - 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) area
- Valley Electric Association (VEA) area

Figure 4-1: Approximated geographical locations of the study areas

4.2 Frequency of the study

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

4.3 Reliability Standards and Criteria

The 2014-2015 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 2015-2024 planning horizon.

4.3.2 NERC Reliability Standards

System Performance Reliability Standards (TPL–001 to TPL–004)

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 TPL 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: System Performance Under Normal Conditions (category A);
- TPL-002: System Performance Following Loss of a Single Bulk Electric System (BES) Element (category B);
- TPL-003: System Performance Following Loss of Two or More BES Elements (category C
- TPL-004: System Performance Following Extreme BES Events (category D); and[4]
- NUC-001 Nuclear Plant Interface Coordination.[4]

4.3.3 WECC Regional Business Practice

The WECC System Performance TPL-001-WECC-RBP-2[5] Regional Business Practice 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]

4.3.4 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.

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[3] http://www.nerc.com/page.php?cid=2%7C20
[4] Analysis of TPL-004 Extreme Events (Category D) or NUC-001 are not included within the Transmission Plan unless these requirements drive the need for mitigation plans to be developed.
[5]http://www.wecc.biz/library/Documentation%20Categorization%20Files/Regional%20Business%20Practices/TPL-001-WECC-RBP-2.pdf
[6] http://compliance.wecc.biz/application/ContentPageView.aspx?ContentId=71
[7] http://www.caiso.com/Documents/TransmissionPlanningStandards.pdf

4.4 Study Horizon

The studies that comply with TPL- 001, TPL- 002, and TPL- 003 will be conducted for both the near-term (2015-2019) and longer-term (2020-2024) per the requirements of the reliability standards. According to the requirements under the TPL- 004 standard, the studies that comply with the extreme events criteria will only be conducted for the short-term scenarios (2015 -2019) per the requirement of the reliability standard.

4.5 Study Years

Within the identified near and longer term study horizons the ISO will be conducting detailed analysis on years 2016, 2019 and 2024[8]. 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[9] in the areas as appropriate.

4.6 Study Scenarios

The 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 4.1.9.

<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 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 4-1 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 4.1.14 to assess their FAC-013-2 Transfer Capability or FAC-014-2 System Operating Limits (SOL) for the planning horizon, as applicable.

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[8] Requirement R1.3.1 of TPL-001 and R1.3.2 of TPL-002, TPL-003 and TPL-004 states: *"Cover critical system conditions and study years as deemed appropriate by the responsible entity."*
[9] Requirement R1.3.1 of TPL-001, TPL-002, TPL-003 and TPL-004 states: "Be supported by a current or past study and/or system simulation…"

Table 4-1: Summary of Study Scenarios in the ISO Reliability Assessment

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2016	**2019**	**2024**
Northern California (PG&E) Bulk System*	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load Spring Peak	Summer Peak Summer Off-Peak
Humboldt	Summer Peak Winter Peak Summer Off-Peak	Summer Peak Winter Peak Summer Light Load	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak Winter peak Summer Off-Peak	Summer Peak Winter Peak Summer Light Load	Summer Peak Winter peak
North Valley	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak
Central Valley (Sacramento, Sierra, Stockton)	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak
Greater Bay Area	Summer Peak Winter peak - (SF & Peninsula) Summer Off-Peak	Summer Peak Winter peak - (SF & Peninsula) Summer Light Load	Summer Peak Winter peak - (SF Only)
Greater Fresno	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak
Kern	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak
Central Coast & Los Padres	Summer Peak Winter Peak Summer Off-Peak	Summer Peak Winter Peak Summer Light Load	Summer Peak Winter Peak
Southern California bulk transmission system	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak Fall Peak
Southern California Edison (SCE) area	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak
San Diego Gas and Electric (SDG&E) area	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak
Valley Electric Association	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak

Note: - Peak load conditions are the peak load in the area of study.
- Off-peak load conditions are approximately 50-65 per cent of peak loading conditions, such as weekend.
- Light load conditions are the system minimum load condition.
- Partial peak load condition represents a critical system condition in the region based upon loading, dispatch and facilities rating conditions.

4.7 Contingencies:

In addition to the system under normal conditions (TPL-001), the following contingencies will be evaluated as part of the study. These contingencies lists will be made available on the ISO secured website

Loss of a single bulk electric system element (BES) (TPL-002 - Category B)

The assessment will consider all possible Category B contingencies based upon the following:

- Loss of one generator (B1)[10]
- Loss of one transformer (B2)
- Loss of one transmission line (B3)
- Loss of a single pole of DC lines (B4)
- Loss of the selected one generator and one transmission line (G-1/L-1)[11], where G-1 represents the most critical generating outage for the evaluated area
- Loss of both poles of the Pacific DC Intertie

Loss of two or more BES elements (TPL-003 - Category C)

The assessment will consider the Category C contingencies with the loss of two or more BES elements which produce the more severe system results or impacts based on the following:

- Breaker and bus section outages (C1 and C2)
- Combination of two element outages with system adjustment after the first outage (C-3)
- Loss of a both poles of DC lines (C4)
- All double circuit tower line outages (C5)
- Stuck breaker with a Category B outage (C6 thru C9)
- Loss of two adjacent transmission circuits on separate towers[12]

Extreme contingencies (TPL-004 - Category D)

The assessment will consider the Category D contingencies of extreme events which produce the more severe system results or impact as a minimum based on the following:

- Loss of 2 nuclear units[13]
- Loss of all generating units at a station.
- Loss of all transmission lines on a common right-of-way
- Loss of substation (One voltage level plus transformers)
- Certain combinations of one element out followed by double circuit tower line outages.

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[10] Includes per California ISO Planning Standards – V Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard.
[11] Per California ISO Planning Standards – IV Combined Line and Generator Outage Standard.
[12] Per requirement R1.1 of WECC System Performance TPL-001-WECC-RBP-2 Regional Business Practice
[13] Per requirement R1.2 of WECC System Performance TPL-001-WECC-RBP-2 Regional Business Practice

4.8 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 4-2 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 February 14, 2013) will be used as a starting point. Dynamic load models will be added to this file.

Table 4-2: Summary of WECC Base Cases used to represent system outside ISO

Study Year	Season	WECC Base Case
2016	Summer Peak	2015 HS3-S
	Winter Peak	2013-14 HW2
	Summer Off-Peak	2014 LS1
2019	Summer Peak	2019 HS2
	Winter Peak	2018-19 HW2
	Summer Light	2014 LS1
	Spring Peak	2014 HSP1
2024	Summer Peak	2023 HS1-S
	Winter Peak	2023-24 HW1
	Summer Off-Peak	2022 LA1-S
	Fall Peak	2023 HS1-S

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 2019 summer peak base case for the northern California will use 2019 HS2 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.

4.9 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.

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. 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, 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.

The CPUC and CEC will provide the ISO with the RPS portfolios to be used in the 2014-2015 transmission planning process in February, 2014. The RPS portfolio submission letter will be posted on the ISO website on the 2014-2015 Transmission Planning Process page. For the reliability assessment the commercial interest portfolio will be used.

Generation included in this year's baseline scenario described in Section 24.4.6.6 of the ISO Tariff will also be included in the 10-year Planning Cases. Given the data availability, generic dynamic data may be used for the future generation.

Thermal generation projects in construction or pre-construction phase: 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.

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.

- <u>Nuclear Retirements</u> – As indicated above Diablo Canyon will be modeled on-line and is assumed to have obtained renewal of licenses to continue operation,
- <u>Once Through Cooled Retirements</u> – As identified below.
- <u>Renewable and Hydro Retirements</u> – Assumes these resource types stay online unless there is an announced retirement date.
- <u>Other Retirements</u> – Unless otherwise noted, assumes retirement based resource age of 40 years or more.

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:

- Base-load Diablo Canyon Power Plant (DCPP) nuclear generation units are modeled on-line;
- Generating units that are repowered, replaced or having firm plans to connect to acceptable cooling technology, as illustrated in Table 4-3;
- All other OTC generating units will be modeled off-line beyond their compliance dates;

OTC replacement local capacity amounts in southern California that were authorized by the CPUC under the LTTP Track-1 will be included. The additional, post-SONGS local capacity amounts proposed or authorized under the CPUC LTTP Track-4 will be included in the studies. If a final decision is not available in time upon commencement of the 2014/2015 transmission planning studies, the local capacity in the CPUC's Proposed Decision for LTPP Track 4 will be modeled offline in the study cases but will be considered as part of the overall mitigations. Table 4-4 provides the local capacity resource additions and the study year in which the amounts will be first modeled based on the CPUC LTPP Track 1 authorization and Proposed Decisions for LTPP Track 4.

Table 4-3: 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)	Final Capacity, if Already Repowered or Under Construction (MW)
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	GenOn proposed to utilize cooling tower of Unit 7 for Units 5&6 if it can obtain long-term Power Purchase & Tolling Agreement (PPTA) with the CPUC and the utilities.
			6	12/31/2017	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	12/31/2017	510	These two OTC combined cycle plants were placed in service in 2002
			2	12/31/2017	510	
			6	12/31/2017	754	
			7	12/31/2017	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	Alternatives of cooling system are to be evaluated by the consultants to the utility and the State Water Resources Control Board
			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	
	Alamitos (2,011 MW)	AES	1	12/31/2020	175	AES proposes to repower with non-OTC generating facilities. This plan is dependent on whether AES can obtain Power Purchase and Tolling Agreement (PPTA) from the CPUC and the utilities.
			2	12/31/2020	175	
			3	12/31/2020	332	
			4	12/31/2020	336	
			5	12/31/2020	498	
			6	12/31/2020	495	

Area	Generating Facility (Total Plant MW)	Owner	Unit	State Water Resources Control Board (SWRCB) Compliance Date	Net Qualifying Capacity (NQC) (MW)	Final Capacity, if Already Repowered or Under Construction (MW)
	Huntington Beach (452 MW)	AES	1	12/31/2020	226	
			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 proposes repowering with a new 558 MW project (Carlsbad Energy Center) - dependent on whether NRG can obtain PPTA from the CPUC and the utilities.
			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)

Table 4-4: OTC/SONGS replacement local capacity resources

LCR Area	Maximum Authorized Local Capacity Addition (LTTP Track-1)		CPUC's Proposed Decision for LTPP Track 4l Capacity Addition (LTTP Track-4)[14]	
	Amount (MW)	Study year in which addition is to be first modeled	Amount (MW)	Study year in which addition is to be first modeled [(1)]
Greater Bay Area	0	N/A	0	N/A
Moorpark Sub-area	290	2021	0	N/A
West LA Basin / LA Basin	1800	2021	Up to 700	2021
San Diego	308	2018	Up to 700	2018

As proxy, generic resources, at the existing sites, will be used for modeling purposes up to the capacity authorized in LTTP Track-1 and proposed decision in LTTP Track-4 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".

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 differ somewhat between locations and seasons as follows:

Table 4-5 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

[14] CPUC Proposed Decisions for LTPP Track 4 (http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=All&DocID=87951536)

Table 4-6 Summary of renewable output in SCE

All years	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 Peak	NQC~=P Max	36%xNQC~= 36%xPmax	0	Low Output

Table 4-7 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	76%xNQC~= 76%xPmax	2.5xNQC~= 77%xPmax	High Output
Sum Peak	NQC~=P Max	55%xNQC~= 55%xPmax	0.1xNQC~= 3%xPmax	Low Output

Table 4-8 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

4.10 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 2013-2014 or earlier ISO transmission plans. Currently, the ISO anticipates the 2013-2014 transmission plan will be presented to the ISO board of governors for approval in March 2014. Once the plan is approved by the board, a complete list of transmission projects will be included in the final Study Plan.

4.11 Demand Forecast

The assessment will utilize the California Energy Demand Forecast 2014-2024 released by California Energy Commission (CEC) dated January 2014 (posted January 10, 2015) using the Mid Case LSE and Balancing Authority Forecast spreadsheet of December 19, 2013.

During 2013, the CEC, CPUC and CAISO engaged in collaborative discussion on how to consistently account for reduced energy demand from energy efficiency in these planning and procurement processes. To that end, the 2013 IEPR final report, published on January 23, 2013, based on the IEPR record and in consultation with the CPUC and the CAISO, recommends using the Mid AAEE scenario for system-wide and flexibility studies for the CPUC 2014 LTPP and CAISO 2014-15 TPP cycles. 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-Mid AAEE scenario for local studies is more prudent at this time.

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

http://www.energy.ca.gov/2013_energypolicy/documents/

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

- The 1-in-10 load forecasts will be used in PG&E, SCE, SDG&E, and VEA local area studies including the studies for the LA Basin/San Diego local capacity area.
- The 1-in-5 load forecast will be used for system studies

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.

4.11.2 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 years 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

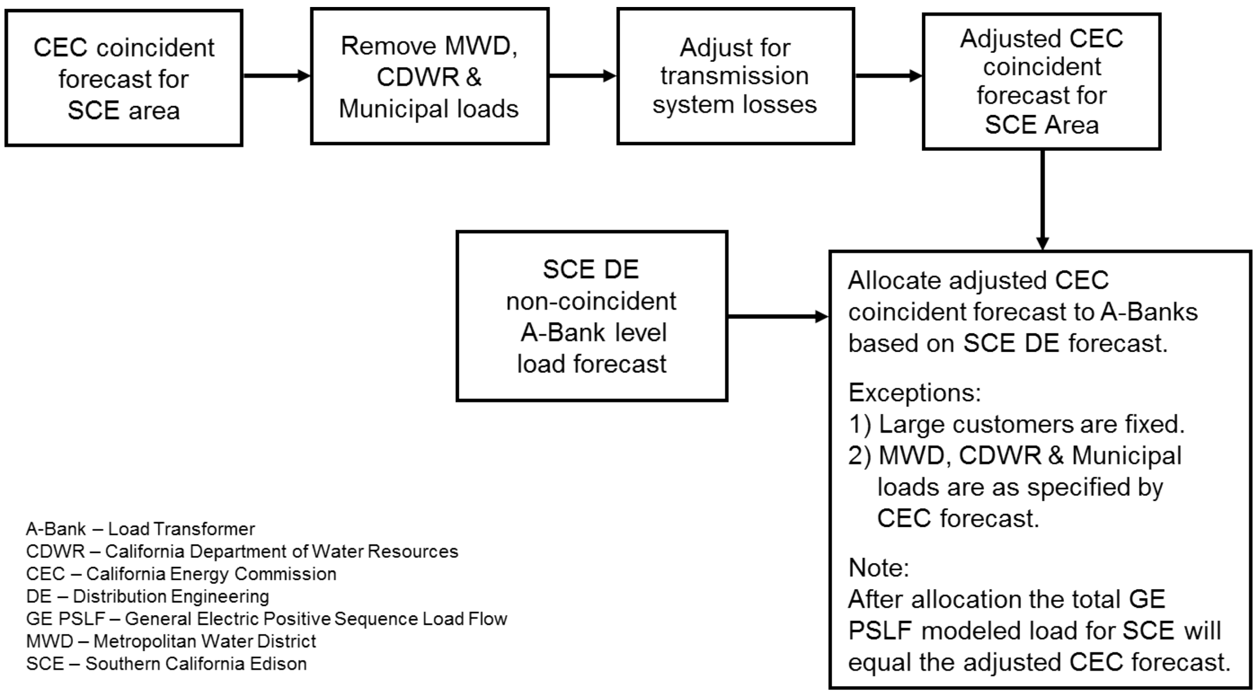
Municipalities provide PG&E their load forecast information. If no information is provided, PG&E supplements such forecast. For example, if a municipal utility provided only the 1-in-5 loads, PG&E would determine the 1-in-2 and 1-in-10 loads by adjusting the 1-in-5 loads for temperature in the same way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

4.11.3 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



4.11.4 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 difference between the adverse and coincident loads includes about 3% of transmission losses - while simulating a single substation or zone peak, transmission losses are neglected because the system is not adjusted to reflect a system-wide coincident peak.

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.

4.11.5 Valley Electric Association Service Area

The VEA substation load forecast is obtained from historical SCADA data and VEA long range study and load plans. The historical SCADA data reflects the actual, measured load on the substation distribution transformers. Both sets of data are compared against the CEC forecast and adjusted as needed.

4.12 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) and other devices. In addition, Table A4-1 of Appendix A provides a list of key 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.

4.13 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.

4.14 Firm Transfer

Power flow on the major paths represents the firm transfer that will be modeled in the study. In general, the northern California (PG&E) system has 4 interties with the outside system and southern California. Out of these 4 ties, Path 66 (COI) and Path 26 are two major transfer paths that wheel large amounts of power between northern California and its neighbors. Consequently, Table 4-9 lists the capability and power flows that will be modeled in each scenario on these paths in the northern area assessment[15].

Table 4-9: Major Path flows in northern area (PG&E system) assessment[16]

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

Note: The contractual arrangement to provide SPS/RAS between CDWR and PG&E will expire in 2014. Assessments will take this into consideration will path flows at transfer levels without the SPS/RAS being available.

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 4-10 lists major paths in southern California along with their current Transfer Capability (TC) or System Operating Limit (SOL) for the planning horizon. Each of these paths will be modeled at their full TC or SOL at least in one southern California bulk system base case for the near-term planning horizon as shown in the table.

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

[16] 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)

Table 4-10: Stressed Path flows in southern area (SCE and SDG&E system) assessment

Path	Transfer Capability/SOL (MW)	Scenario in which Path will be stressed
Path 26 (N-S)	4000	Summer Peak
PDCI (N-S)	3100	
West of River (WOR)	11,200	Summer Light or Off Peak
East of River (EOR)	9,600	Summer Light or Off Peak
San Diego Import	2850	Summer Peak
SCIT	17,870	Summer Peak

4.15 Protection System

To help ensure reliable operations, many special protection systems (SPS), safety nets, UVLS and UFLS schemes have been installed in some areas. Typically, these systems trip load and/or generation by strategically tripping 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.

4.16 Control Devices

Several control devices will also be modeled in the studies. These control devices are:

- All shunt capacitors in SCE and other areas
- Static Var Compensators and Synchronous Condensers at several locations such as Potrero, Newark, Rector, Devers, and Talega substations
- DC transmission line such as PDCI, IPPDC, and Trans Bay Cable Projects
- Imperial Valley flow controller; the details on which technology to use (i.e., phase shifting transformer or back-to-back DC) will be provided prior to commencement of studies.

4.17 Demand Response Programs and Energy Storage

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 information for consideration in planning studies from the following:

- Pacific Gas & Electric (PG&E)
- Eagle Crest Energy Company
- Alton Energy

PG&E recommended that the estimated load impacts from demand response programs allocated to the bus bar level using the methodology that was developed through the joint effort between the CAISO, CEC, CPUC and IOUs for the 2012 LTPP, Track IV sensitivity analysis be used in the 2014-2015 TPP. PG&E also identified the following two energy storage facilities for inclusion in the TPP Planning assumptions within their system.

- Vaca-Dixon 2 MW, 2MWh Battery Energy Storage System
- Yerba Buena 4 MW, 28 MWh Battery Energy Storage System.

The submission from Eagle Crest Energy Company and Alton Energy provides an alternative for transmission interconnection in the area of specific generation. This could be considered in the future if resubmitted in the Request Window to address specific constraints identified in the assessment.

4.17.2 Demand Response

Not all of the programs from the default DR capacity assumption are counted, due to uncertainty in the ability of those DR programs to mitigate first contingencies under an N-1-1 condition (as defined by NERC reliability criteria). In the 2012 LTPP Track 4, the subset of DR programs that are "fast response", and located in the most effective areas for mitigating first contingencies under an N-1-1 condition, were identified as an acceptable assumption for local area studies. "Fast response" in the Track 4 context refers to the expectation that such DR would be able to respond in sufficiently less time than 30 minutes from the CAISO dispatch, to allow ISO operators enough time to detect a non-response and dispatch an alternative resource if needed to mitigate a contingency. The table below identifies the programs and capacities for each IOU that meets the "fast response" criteria. DR capacity will be allocated to busbar using the method defined in D.12-12-010.

Table 4-11: DR Capacity in Local Area Reliability Studies

"Fast Response" DR Program MW in 2024	PG&E	SCE	SDG&E
BIP	287	627	1
API	n/a	69	n/a
AC Cycling Residential	82	298	12
AC Cycling Non-Residential	1	76	3

4.17.3 Energy Storage

The locations for this new storage capacity must be assumed. It is reasonable to assume that cost-effectiveness requirements for new storage capacity will lead to siting at the most effective locations to contribute to local area reliability. The 2014-15 TPP will identify transmission constraints in the local areas, the CAISO will identify the effective busses that the assumed storage capacity identified in the table above can be distributed amongst within the local area as potential development sites. The table below 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, or specific busbar allocations provided by the IOUs.

Table 4-12: Storage Operational Attributes

Values are MW in 2024	**Transmission-connected**	**Distribution-connected**	**Customer-side**
Total Installed Capacity	700	425	200
Amount providing capacity/ ancillary services	700	212.5	0
Amount with 2 hours of storage	280	85	0
Amount with 4 hours of storage	280	85	0
Amount with 6 hours of storage	140	42.5	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 unit is charged at 25 MW, it will take 4.8 hours to charge.			

4.18 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 steady state, post-transient and transient stability studies. However, other tools such as TARA for contingency processing or 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 B, C, and D 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.

4.19 Study Methodology

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

Power Flow Contingency Analysis

The ISO will perform power flow contingency analyses based on the ISO Planning Standards[17] 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 A (TPL 001), against normal ratings and normal voltage ranges, as well as emergency conditions NERC Category B (TPL 002), C (TPL 003) and D (TPL 004) 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)[18]. 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.

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

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 PG&E, SCE, and SDG&E area bulk system assessments and if there are thermal overloads on the bulk system.

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.

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[17] California ISO Planning Standards are posted on the ISO website at http://www.caiso.com/docs/09003a6080/14/37/09003a608014374a.pdf

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

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 of 5% voltage deviation for “N-1” contingencies and 10% voltage deviation for “N-2” contingencies.

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 A) and for single contingencies (Category B). For multiple contingencies (Category C), 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 B and 2.5% for Category C contingencies 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 including Rio Oso, Fresno, and Southern California, including the L.A. Basin and San Diego areas.

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 as in Table 4-13 are met.

Table 4-13: WECC Transient Stability Criteria

<table>
<tr><th>Performance Level</th><th>Disturbance</th><th>Transient Voltage Dip Criteria</th><th>Minimum Transient Frequency</th></tr>
<tr><td rowspan="4">B</td><td>Generator</td><td rowspan="4">Max V Dip – 25%
Max Duration of V Dip Exceeding 20% - 20 cycles
Not to exceed 30% at non-load buses.</td><td rowspan="4">59.6 Hz for 6 cycles or more at a load bus.</td></tr>
<tr><td>One Circuit</td></tr>
<tr><td>One Transformer</td></tr>
<tr><td>PDCI</td></tr>
<tr><td rowspan="3">C</td><td>Two Generators</td><td rowspan="3">Max V Dip – 30% at any bus.
Max Duration of V Dip Exceeding 20% - 40 cycles at load buses</td><td rowspan="3">59.0 Hz for 6 cycles or more at a load bus.</td></tr>
<tr><td>Two Circuits</td></tr>
<tr><td>IPP DC</td></tr>
</table>

In addition, the reliability assessment included the following study assumptions:

Power Factor Assumption

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 value of this ratio recorded for the last five years has ranged between 35 to 1 in 2006 to a leading power factor from 2008 through 2010.

The increase in 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.

Recent Historical System WATT / VAR Ratio:

The WATT / VAR ratio recorded for SCE transmission substation loads during the annual peak load for the past five years are as follows:

- 2006 – 35
- 2007 – 52
- 2008 – leading power factor
- 2009 – leading power factor
- 2010 – leading power factor

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 2014 and 2015 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.

The technical studies mentioned in this section will be used for identifying mitigation plans for addressing reliability concerns. As per section 24.4.6.2 of the tariff, the ISO, in coordination with each Participating TO with a PTO Service Territory will, as part of the Transmission Planning Process and consistent with the procedures set forth in the Business Practice Manual, identify the need for any transmission additions or upgrades required to ensure System reliability consistent with all Applicable Reliability Criteria and CAISO Planning Standards. 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, Remedial Action Schemes, appropriate Generation, interruptible Loads, storage facilities or reactive support.

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:

- 2015 – Local Capacity Area Technical Study
- 2019 – 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, 2014.

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 18 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 2014-2015 ISO Transmission Planning Process webpage.

5.2 Long-Term Local Capacity Requirement Assessment

Similar to the Near-Term Local Capacity Requirement assessment, the Long-Term Local Capacity Requirement studies focus on determining the minimum MW capacity requirement within each of local areas inside the ISO Balancing Authority Area. The Long-Term LCR assessment will be submitted to the CPUC as a part of the 2014/2015LTPP process identifying the capacity needs within the local areas.

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 capacity procurement.

Scenarios: The local capacity studies will be performed:

- 2024 – Long-Term Local Capacity Requirements

The assumptions developed for the Reliability Assessment in Section 3 will be used in these studies.

Methodology: The study methodology used in the Near-Term LCR Assessment is documented in the LCR manual and will also 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

6. Special Studies

6.1 San Francisco Peninsula Extreme Event Assessment

The reliability standards require the ISO to assess the impacts of category D extreme events; however they do not mandate that the consequences be mitigated – the need for mitigations is based on the specific circumstances and consequences by the responsible planning entities. In addition, the contingencies identified as being the most critical are beyond the contingencies identified within the NERC Reliability standards. In the 2013-2014 TPP the ISO continued the assessment of extreme events in the San Francisco Peninsula area. As a part of this assessment , the ISO determined that there are unique circumstances affecting the San Francisco area that form a credible basis for considering mitigations of risk of outages and of restoration times that are beyond the minimum reliability standards. The Peninsula area does have unique characteristics in the western interconnection due to the urban load center, geographic and system configuration, and potential risks with challenging restoration times for these types of events.

With this it is critical for the electric system, transmission and distribution, to have a restoration strategy that will bring the system back. This would include sparing equipment and plans to run temporary supply lines until the damaged facilities can be repaired or replaced. Further, the analysis concluded that in the event that additional transmission system reinforcement is considered necessary, the addition of a new 230 kV transmission line from Morago substation to Potrero substation would be the preferred mitigation plan to further manage the risks of an extreme event in the San Francisco Peninsula area.

However, the ISO determined in the 2013-2014 TPP that further analysis of the reliability risks and the benefits that potential reinforcement options would have in reducing those risks is needed.. This analysis will include further assessing the risk of earthquakes and the probabilities of different magnitude of seismic events in the area and the withstand design capabilities of transmission facilities that are within the San Francisco Peninsula area relative to these potential seismic events. This will involve scenario analysis to compare the relative performance of the system to be able to supply the load in the area under extreme events that affect single transmission facilities or significant critical infrastructure in the San Francisco area. This would include impacts to Martin, San Mateo, Potrero, Embarcadero and/or the distribution supply stations.

6.2 Preferred Resource and Storage Evaluation Technical Studies

The ISO issued a paper[19] on September 4, 2013, in which it presented a methodology to support California's policy emphasis on the use of preferred resources18 – 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

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

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 the 2013-2014 planning cycle, the ISO applied a variation of this new approach in the LA Basin and San Diego areas due to the unique circumstances in these areas. Because of the magnitude of the projected reliability needs in these areas incremental transmission options were also studied to complement non-conventional alternatives (i.e., preferred resources), to reduce the need for conventional generation to fill the gap. Thus, unlike the generic application of the methodology in future transmission planning process cycles where preferred resources are considered as an alternative to transmission, the main focus of this effort with respect to the LA Basin and San Diego was to evaluate non-conventional alternatives and identify performance attributes needed from these alternatives that could effectively address the local reliability needs in these two priority areas as part of a basket of resources.

The ISO plans to continue the preferred resource analysis in the LA Basin and San Diego area as well as other parts of the ISO controlled grid to refine the evaluation of effectiveness of preferred resources based on their particular characteristics. In addition to summer peak load conditions the studies may also consider peak load conditions during other seasons.

In addition, the ISO is working with the utilities, and intends to consult with industry through the course of the summer, to establish the characteristics that demand response programs and storage need in order to be viable transmission mitigations. The ISO will work with the utilities to identify those programs that have the appropriate characteristics such that they can be considered when alternatives are developed and compared once the study results testing system reliability have been completed, and options are being explored.

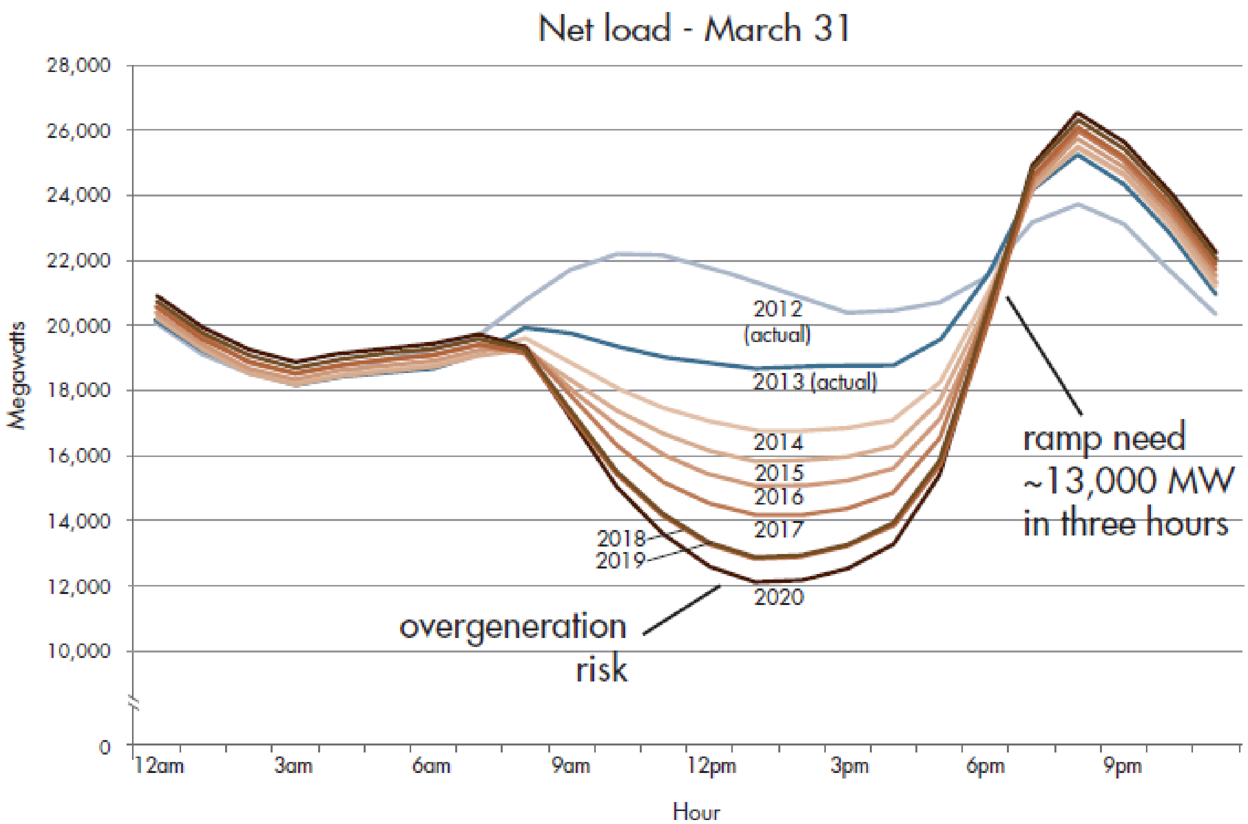
As indicated above and elsewhere in this study plan, the ISO will be considering the applicability of the existing demand response within the Reliability Assessment as potential mitigations to transmission constraints. Further, as indicated in section 4.1.9 ISO will also incorporate incremental uncommitted energy savings in the forecast utilized in the studies. Within the RPS Transmission planning assessment, the ISO will be assessing the High Distributed Generation scenario reflecting grid-connected distributed generation provided by the CPUC, and further notes that the CEC demand forecast accounts for “behind the meter” distribution connected generation.

6.3 Potential Risk of Over Generation

The objective of this study is to assess quantify the potential risk of over-generation conditions that are expected to occur on the system by 2020. The study will assess the ISO's frequency response requirements of the NERC Reliability Standard BAL-003-1.

Over-generation occurs when there is more internal generation and imports into a balancing area than load and exports. The risk of overgeneration is illustrated on the duck curve in Figure 6-1. Typically, before an over-generation event occurs, the system operator will exhaust all efforts to send dispatchable resources to their minimum operating levels and will have used all the decremental energy (DEC) bids available in the imbalance energy market. If no DEC bids or insufficient DEC bids are received, the system operator may declare an over-generation condition if high system frequency and associated high ACE can no longer be controlled. With a high ACE, the energy management system (EMS) will dispatch regulation resources to the bottom of their operating range. Also, operators will make arrangements to sell excess energy out of the market to the extent bids to balance the system is exhausted.

Figure 6-1: The duck curve shows steep ramping needs and overgeneration risk[20]



The following are some reliability issues to be considered as a result of overgeneration to be considered as a part of the assessment.to avoid over-generation situations:

- Meeting frequency response requirements of reliability standards.
- System frequency is higher than 60 Hz,
- Real-time energy market prices may be negative — the ISO must pay internal or external entities to consume more or produce less power,
- ACE is higher than normal and can result in reliability issues, ,
- Grid operators have difficulties controlling the system due to insufficient flexible capacity,
- Insufficient frequency responsive generation on-line may reduce the system ability to quickly arrest frequency decline following a disturbance,
- Inability to shut down a resource because it would not have the ability to restart in time to meet system peak.

[20] http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

7. Policy Driven 33% RPS Transmission Plan Analysis

7.1 Study methodology

The goal of the 33% renewable resource analysis is to identify the transmission needed to meet the 33% renewable resource target in the study year which, for this cycle, is 2024. The first step in this analysis is to establish renewable portfolios to be considered that are aligned closely with the portfolios developed by CPUC and used by the ISO in its renewable integration studies. In accordance with tariff Section 24.4.6.6, the renewable portfolios reflect such considerations as environmental impact, commercial interest and available transmission capacity, among other criteria.

In the last planning cycle, the ISO performed the 33% renewable resource analysis for 2023. Because the base portfolio was modeled in the reliability studies, the results of that study were also considered part of the 33% renewable resource analysis. To supplement those study results, additional studies were performed as described below:

1) Conduct production simulation of the developed portfolios using the ISO unified economic assessment database with renewable portfolios modeled.
2) Conduct additional power flow and stability assessments including
    - Contingency analysis using regular power flow (GE PSLF)
    - Voltage stability assessment using governor power flow (post-transient)
    - Transient stability using GE PSLF
    - Deliverability assessment
3) Categorize any identified transmission upgrade or addition elements based on the tariff Section 24.4.6.6 requirements.

In the 2014-2015 planning cycle, similar methodology will be used to identify the transmission need to meet 33% RPS in 2024.

The CPUC and CEC will be providing the ISO with the RPS portfolios to be used in the 2014-2015 transmission planning process in February, 2014. The RPS portfolio submission letter will be posted on the ISO website on the 2014-2015 Transmission Planning Process page.

7.2 Study scope

The study scope of the 33% renewable resource analysis in this planning cycle includes the following items:

- Model base portfolio in the 2024 reliability assessment. Off-peak base cases will include stress renewable dispatch, so these results identify transmission needs associated with the 33% RPS base portfolio.
- Develop ISO supplemental 2024 power flow base cases starting from 2024 reliability base cases to model different load conditions based on the study methodology and assumptions.
- Establish portfolios and areas to be studied.
- Model those portfolios in production, power flow, and stability models
- Analyze stressed power flow models for peak, off-peak and other scenarios if needed. These should capture conditions for the CAISO's controlled grid and the entire Western Interconnection that show stressed patterns including cases possibly in different seasons. The peak load scenario uses CEC 1-in-5 coincident peak load with the Mid AAEE.
- Update 33% RPS transmission plan based on findings.

- Several sensitivity cases may be created to evaluate different scenarios as part of the comprehensive plan analysis

7.3 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 GIP 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.

<u>LGIP Network Upgrade Criteria for TPP Assessment</u>

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

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

<u>Notification of Network Upgrades being assessed in the TPP</u>

In approximately June – July 2014, the ISO will publish the list of GIP 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 GIP Network Upgrades. GIP 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 GIP 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 GIP.

All generation projects in the Phase II cluster study have the potential to create a need for GIP 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.

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 33% RPS Transmission Plan Analysis. The 1-in-2 demand forecast will be used in the assessment with the Mid AAEE assumption. The Economic Planning Study will conduct 8760 hourly analysis for year 2019 (the 5th planning year) and 2024 (the 10th planning year) respectively through production simulation.

As part of the requirements under the ISO tariff and Business Practice Manual, Economic Planning Study Requests based on the 2013-2014 transmission plan may be submitted to the ISO during the comment period following the stakeholder meeting to discuss this Study Plan. The ISO will evaluate the Study Requests that are received and determine the High Priority Study Requests that will be studies during the 2014-2015 cycle (see tariff Section 24.3.4.2). A list of the selected High Priority Study Requests for this planning cycle will be included in the final study plan.

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. 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 5-1: SMEs for Technical Studies in 2014-2015 Transmission Planning Process

Item/Issues	SME	Contact
Reliability Assessment in PG&E	Catalin Micsa	cmicsa@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	Yi Zhang	yzhang@caiso.com
Near-Term Local Capacity Requirements	Catalin Micsa	cmicsa@caiso.com
Long-Term Local Capacity Requirements	David Le	Dle@caiso.com
Economic Planning Study	Binaya Shrestha Luba Kravchuk	bshrestha@caiso.com lkravchuk@caiso.com
Long-term Congestion Revenue Rights	Chris Mensah-Bonsu	cmensah@caiso.com
Preferred Resource and Storage Evaluation Studies	Nebiyu Yimer	nyimer@caiso.com

11. Stakeholder Comments and ISO Responses

All the comments the ISO receives from stakeholders on this 2014-2015 draft study plan and ISO's responses will be posted to the following link:

http://www.caiso.com/planning/Pages/TransmissionPlanning/2014-2015TransmissionPlanningProcess.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
	Pacific Lumber	32.5
	LP Samoa	25
	Fairhaven	17.3
	Blue Lake	12
	Humboldt Area Total	**258**
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

Planning Area	Generating Plant	Maximum Capacity
	Geysers 20	118
	Bottle Rock	55
	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	**1,619**
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

Planning Area	Generating Plant	Maximum Capacity
	Wolfskill Energy Cener	60
	Lambie, Creed and Goosehaven	143
	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

Planning Area	Generating Plant	Maximum Capacity
	Oxbow Power House	6
	Ralston Power House	83
	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

Planning Area	Generating Plant	Maximum Capacity
	Tiger Creek Power House	55
	US Wind Power Farms	158
	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	243
	Delta Energy Center	965
	Marsh Landing	774
	Russel City – East Shore EC	600
	High Winds, LLC	162
	Los Esteros Critical Energy Facility	293
	Los Medanos Energy Center	678

Planning Area	Generating Plant	Maximum Capacity
	Mariposa Peaker	196
	Metcalf Energy Center	575
	Oakland C Gas Turbines	165
	Donald Von Raesfeld Power Plant	182
	Pittsburg Power Plant	1,360
	Riverview Energy Center	61
	Ox Mountain	13
	Gateway Generating Station	599
	Greater Bay Area Total	**7048**
PG&E - Greater Fresno Area	Fresno Cogen-Agrico	79.9
	Balch 1 PH	31
	Balch 2 Pho	25
	Mendota Biomass Power	107
	Chow 2 Peaker Plant	52.5
	Chevron USA (Coalinga)	25
	Chow II Biomass to Energy	12.5
	Coalinga Cogeneration Company	46
	CalPeak Power – Panoche LLC	49
	Crane Valley	0.9
	Corcoran PB	20
	Dinuba Generation Project	13.5
	El Nido Biomass to Energy	12.5
	Exchequer Hydro	94.5
	Fresno Waste Water	9
	Friant Dam	27.3

Planning Area	Generating Plant	Maximum Capacity
	GWF Henrietta Peaker Plant	109.6
	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
	Kerkhoff PH1	32.8
	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
	McSwain Hydro	10
	Merced Falls	4
	O'Neill Pump-Gen	11
	Panoche Energy Center	410
	Pine Flat Hydro	189.9
	Sanger Cogen	38
	San Joaquin 2	3.2
	San Joaquin 3	4.2
	Starwood Panoche	121.8
	Stratford	20
	Rio Bravo Fresno (AKA Ultrapower)	26.5
	Wellhead Power Gates, LLC	49

Planning Area	Generating Plant	Maximum Capacity
	Wellhead Power Panoche, LLC	49
	Wishon/San Joaquin #1-A Aggregate	20.4
	Greater Fresno Area Total	**3,587.7**
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
	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

Planning Area	Generating Plant	Maximum Capacity
	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
	Ultra Power (OGLE)	45
	University Cogen	36
	New RPS Units	55
	Kern Area Total	**3,588**
PG&E - Central Coast and Los Padres	Moss Landing Power Plant	2,600
	Soledad Energy	10
	Basic Energy Cogen (King City)	120
	King City Peaker	61
	Sargent Canyon Cogen (Oilfields)	50
	Salinas River Cogen (Oilfields)	45
	Diablo Canyon Power Plant	2,400
	Morro Bay Power Plant (#3 & #4)	680
	Union Oil (Tosco)	6
	Santa Maria	8
	Vandenberg Air Force Base	15
	Topaz	550

Planning Area	Generating Plant	Maximum Capacity
	California Valley Solar	250
	Central Coast and Los Padres Area Total	**6,795**

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
	Warne 2	38.0

Planning Area	Generating Plant	Maximum Capacity
	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
	Suncreek (Alta 2012)	168.0
	CPC Alta Wind 4-5 (fka CPC East)	550.0
	CPC Alta Wind 1-3 (fka CPC West)	600.0
	Windstar I Alternate	120.0
	North Sky River Wind	162.0
	Avalon Solar	110.0
	KR 3-1	22.8
	KR 3-2	21.5
	LakeGen	18.0

Planning Area	Generating Plant	Maximum Capacity
	Wellhead Power Delano	49.9
	Kawgen	18.0
	Arbwind	21.8
	Canwind	65.0
	Enwind	47.1
	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
	Borel	10.0
	Alta Vista Suntower Generating Station	66.0
	Antelope Power Plant	20.0
	Dawn Gen	20.0
	Twilight Gen	20.0
	Tehachapi and Big Creek Corridor Total	**5,478**
SCE - East of Lugo Area	Desert Star Energy Star	495
	Mountain Pass - Ivanpah Solar	400
	Copper Mountain Solar I	58
	East of Lugo Area Total	**953**

Planning Area	Generating Plant	Maximum Capacity
SCE - North of Lugo	BSPHYD 26	13.4
	BSPHYD 34	15.8
	Poole	10.9
	Lundy	3.0
	Rush Creek	11.9
	Casa Diablo	30.0
	BLM (E7G, E8G & W9G)	100.7
	Borax I	48.0
	Calgen (1G, 2G, & 3G)	92.2
	Kerrgen	25.6
	Kerr McGee	55.0
	Luz (8 & 9)	160.0
	McGen	118.3
	MoGen G	62.5
	NavyII (4G, 5G, & 6G)	99.0
	Oxbow G1	56.0
	Segs (1 & 2)	38.4
	Sungen (3G, 4G, 5G, 6G, & 7G)	160
	Alta 1G	65.0
	Alta 2G	81.0
	Alta 3ST	108.0
	Alta 4ST	108.0
	Alta 31GT	66.5
	Alta 32GT	66.5
	Alta 41GT	66.5

Planning Area	Generating Plant	Maximum Capacity
	Alta 42GT	66.5
	HDPP Energy Facility	830.0
	North of Lugo Area Total	**2,559**
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

Planning Area	Generating Plant	Maximum Capacity
	Buchwind QF	17
	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
	Eastern Area Total	**1,470**
SCE Metro Area	Alamitos	2,010
	Canyon Power Plant	195
	Anaheim CT	41
	Watson Cogeneration	271
	Barre Peaker	45
	Broadway 3	65
	Center Area Lumped Units	18
	MWD Rio Hondo Hydroelectric Recovery Plant	2
	Center Peaker	45
	Century	36
	O.L.S. Energy Company- Chino-Mens Inst.	25

Planning Area	Generating Plant	Maximum Capacity
	Ripon Cogeneration	27
	Milliken Landfill Project	1
	Agua Mansa Generating Facility	43
	Clearwater Power Plant	28
	Diamond Valley P-G Plant	1
	Drews	36
	Devil Canyon	235
	El Segundo 3 & 4	670
	Fontana/Lytle Creek Hydro	1
	Grapeland Peaker	43
	Etiwanda Hydro Recovery Plant	10
	Mid Valley Landfill Project	2
	Etiwanda 3 & 4	640
	Glen Arm Power Plant	132
	Harbor Cogen Combined Cycle	100
	BP West Coast Products	21
	Long Beach 1 – 4	260
	City Of Long Beach	28
	Huntington Beach 1 & 2	452
	Inland Empire Energy Center	670
	MWD Venice Hydroelectric Recovery Plant	4
	Carson Cogeneration Company	47
	MWD Corona Hydroelectric Recovery Plant	2
	MWD Temescal Hydroelectric Recovery Plant	2
	Corona Energy Partners, Ltd.	30

Planning Area	Generating Plant	Maximum Capacity
	Mira Loma Peaker	43
	Lake Mathews Hydro Recovery Plant	5
	Mojave Siphon PH	18
	MWD Coyote Creek Hydroelectric Recovery Plant	3
	Olinda Area Lumped Units	1
	Olinda Landfill	5
	Ontario/Sierra Hydro Project	1
	San Dimas Hydro Recovery Plant	8
	Padua Area Lumped Units	1
	San Dimas Wash Hydro	1
	Redondo	1,356
	Riverside Energy Resource Center (RERC)	194
	Springs Generation Plant	36
	Coyote Canyon	6
	Mountainview Power Plant	969
	Mill Creek Hydro Project	1
	MWD Perris Hydroelectric Recovery Plant	8
	MWD Red Mountain Hydroelectric Recovery Plant	2
	Badlands Landfill Gas to Energy Facility	1
	El Sobrante Landfill Gas Generation	1
	H. Gonzales Gas Turbine	12
	Malburg Generating Facility	134
	MWD Valley View Hydroelectric Recovery Plant	4
	L.A. County Sanitation District #2 (Puente Hills B)	47

Planning Area	Generating Plant	Maximum Capacity
	MM West Coast Covina, LLC	6
	Ellwood Generating Station	54
	Exxon Company, USA	1
	Gaviota Oil Heating Facility	1
	MM Tajiguas Energy, LLC	3
	Mandalay 1 & 2	430
	Mandalay 3 GT	130
	Calabasas Gas-to-Energy Facility	7
	Simi Valley Landfill Gas Generation	1
	Ormond Beach	1,516
	Toland Landfill Gas to Energy Project	1
	Foothill Hydro Recovery Plant	8
	County Of Los Angeles (Pitchess Honor Ranch)	19
	Saugus Area Lumped Units	1
	Chiquita Canyon Landfill Generating Facility	7
	MM Lopez Energy, LLC	5
	E. F. Oxnard, Incorporated	34
	Procter & Gamble Paper Prod. (Oxnard II)	46
	Weyerhaeuser Company (Formerly Williamette Industries)	13
	Berry Petroleum Placerita	37
	Metro Area Total	**11,415**

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

Planning Area	Generating Plant	Maximum Capacity
SDG&E	Encina 1	106
	Encina 2	103
	Encina 3	109
	Encina 4	299
	Encina 5	329
	Palomar	565
	Otay Mesa	603
	Encina GT	14
	Kearny GT1	15
	Kearny 2AB (Kearny GT2)	55
	Kearny 3AB (Kearny GT3)	57
	Miramar GT 1	17
	Miramar GT 2	16
	El Cajon GT	13
	Goalline	48
	Naval Station	47
	North Island	33
	NTC Point Loma	22
	Sampson	11
	NTC Point Loma Steam turbine	2.3
	Ash	0.9
	Cabrillo	2.9
	Capistrano	3.3
	Carlton Hills	1.6

Planning Area	Generating Plant	Maximum Capacity
	Carlton Hills	1
	Chicarita	3.5
	East Gate	1
	Kyocera	0.1
	Mesa Heights	3.1
	Mission	2.1
	Murray	0.2
	Otay Landfill I	1.5
	Otay Landfill II	1.3
	Covanta Otay 3	3.5
	Rancho Santa Fe 1	0.4
	Rancho Santa Fe 2	0.3
	San Marcos Landfill	1.1
	Miramar 1	46
	Larkspur Border 1	46
	Larkspur Border 2	46
	MMC-Electrovest (Otay)	35.5
	MMC-Electrovest (Escondido)	35.5
	El Cajon/Calpeak	42
	Border/Calpeak	42
	Escondido/Calpeak	42
	El Cajon Energy Center	48
	Miramar 2	46
	Orange Grove	94
	Kumeyaay	50

Planning Area	Generating Plant	Maximum Capacity
	Bullmoose	20
	Lake Hodges Pumped Storage	40
	Ocotillo Express	299
	Breggo Solar	21
	SDG&E Area Total	**3,445**

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	Oakley Generation Station (Construction)	624	2016
SCE	Abengoa Mojave Solar Project (Construction)	250	2014
	Genesis Solar Energy Project (Construction)	250	2014
	Ivanpah Solar (Construction)	370	2014
	Blythe Solar Energy Center (Construction)	485	2015
SDG&E	Carlsbad (Pre-Construction)	558	2017
	Pio Pico Energy Center (Pre-Construction)	300	2015

A3 Retired Generation

Table A3-1: Generation plants projected to be retired in planning horizon

PTO Area	Project	Capacity (MW)	First Year to be retired
PG&E	Contra Costa 6	337	2013*
	Contra Costa 7	337	2013*
	GWF Power Systems 1-5	100	2013
	Morro Bay 3	325	2014
	Morro Bay 4	325	2014
SCE	El Segundo 3	335	2013**
SDG&E	Kearny Peakers	135	TBD
	Miramar GT1 and GT2	36	TBD
	El Cajon GT	16	TBD

Notes: * Contra Costa units 6 and 7 were retired when the Marsh Landing generation project became commercially available.

** El Segundo unit 3 was retired when the El Segundo Power Redevelopment project became commercially available.

A4 Reactive Resources

Table A4-1: Summary of key 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 230kV and Devers 500kV	156 MVAR; and 605 MVAR (based on 525kV)*
Sunrise San Luis Rey 230 kV	63
Southbay / Bay Boulevard 69 kV (expected in 2014)	100
Miraloma	158
Suncrest	126
Penasquitos 230 kV	126

* Dynamic capability

A5 Special Protection Schemes

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

PTO	Area	SPS Name
PG&E	Central Coast / Los Padres	Mesa and Santa Maria Undervoltage SPS
	Central Coast / Los Padres	Divide Undervoltage SPS
	Central Coast / Los Padres	Temblor-San Luis Obispo 115 kV Overload Scheme (TBD)
	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)

PTO	Area	SPS Name
	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

PTO	Area	SPS Name
	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	Big Creek Corridor	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
	Big Creek Corridor	Midway-Vincent RAS
	Big Creek Corridor	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 and Eagle Mountain Thermal Overload Scheme
	Metro Area	El Nido N-2 Remedial Action Scheme
	Metro Area	Mountainview 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

PTO	Area	SPS Name
	Metro Area	Valley Direct Load Trip Remedial Action Scheme

Table A5-3: Existing key Special Protection Schemes in the SDG&E

PTO	Area	SPS Name
SDG&E	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
	SDG&E	230kV TL 23040 Otay Mesa – Tijuana SPS Note: This SPS is currently disabled and will be watched if there is any implications for CFE to reactive this scheme.
	SDG&E	500kV TL 50003 Gen Drop SPS
	SDG&E	500kV TL 50005 Gen Drop SPS