2013-2014 Transmission Planning Process Unified Planning Assumptions and Study Plan

February 22, 2013

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1. Introduction

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

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

The objectives of the unified planning assumptions and study plan are to clearly articulate the goals of, and agree upon 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 2013-2014 comprehensive transmission plan at the end of Phase 2.

2. Overview of 2013-2014 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 2013-2014 transmission planning cycle is provided in Table 2-1. Should this schedule change or other aspects of the 2013-2014 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 2013-2014 planning cycle

Phase	No	Due Date	2013-2014 Activity
Phase 1	1	December 18, 2012	The ISO sends a letter to neighboring balancing authorities, sub-regional, regional planning groups requesting planning data and related information to be considered in the development of the Study Plan and the ISO issues a market notice announcing a thirty-day comment period requesting demand response assumptions and generation or other non-transmission alternatives to be considered in the Unified Planning Assumptions.
	2	December 19, 2012	The ISO sends market notice requesting information on existing demand response and generation or other non-transmission assumptions to be included in study plan.
	3	January 18, 2013	PTO's, neighboring balancing authorities, regional/sub-regional planning groups and stakeholders provide ISO the information requested in the December 15 letter and market notice (see no.1 above)
	4	January 21, 2013	Comment period for stakeholders to submit information on existing demand response and generation or other non-transmission assumptions.
	5	February 22, 2013	The ISO develops the draft Study Plan and posts it on its website
	6	February 28, 2013	The ISO hosts public stakeholder meeting #1 to discuss the contents in the Study Plan with stakeholders
	7	February 28 - March 14, 2013	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	Last week in March	The ISO specifies a provisional list of high priority economic planning studies, finalizes the Study Plan and posts it on the public website
	9	Q2	ISO Initiates the development of the Conceptual Statewide Plan
Phase 2	10	July/August	ISO posts the Conceptual Statewide Plan on its website and issues a market notice announcing the posting
	11	August/September	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)
	12	August 15, 2013	Request Window opens
	13	August 15, 2013	The ISO posts preliminary reliability study results and mitigation solutions
	14	September 16, 2013	PTO's submit reliability projects to the ISO
	15	September 25 – 26, 2013	The ISO hosts public stakeholder meeting #2 to discuss the reliability study results, PTO's reliability projects, and the Conceptual Statewide Plan with stakeholders
	16	September 26 – October 10, 2013	Comment period for stakeholders to submit comments on the public stakeholder meeting #2 material
	17	October 15, 2013	Request Window closes
	18	End of October 2013	ISO post final reliability study results and mitigation solutions
	19	November 13, 2013	The ISO posts an update on the preliminary policy driven & economic planning study results on its website

Phase	No	Due Date	2013-2014 Activity
	20	November 20 - 21, 2013	The ISO hosts public stakeholder meeting #3 to provide the updates on the preliminary policy driven & economic planning study results
	21	November 21 – December 5, 2013	Comment period for stakeholders to submit comments on the public stakeholder meeting #3 material
	22	December 18 – 19, 2013	The ISO to brief the Board of Governors of projects under $50 million to be approved by ISO Executive
	23	January 2014	The ISO posts the draft Transmission Plan on the public website
	24	February 2014	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	Three weeks following the public stakeholder meeting #4	Comment period for stakeholders to submit comments on the public stakeholder meeting #4 material
	26	March 2014	The ISO finalizes the comprehensive Transmission Plan and presents it to the ISO Board of Governors for approval
	27	End of March	ISO posts the Final Board-approved comprehensive Transmission Plan on its site
Phase 3	28	April 1, 2014 – June 2, 2014	If applicable, the ISO solicits proposals to finance, construct, and own economically driven and category 1 policy driven elements identified in the Transmission Plan (No. 24 above)
	29	No later than June 9, 2014	The ISO posts the list of interested project sponsors received
	30	No later than June 23, 2014	The ISO posts the list of qualified project sponsors who met the established criteria
	31	Within 7 calendar days after posting the list of qualified project sponsors	If two or more project sponsors submitted proposals for the same elements(s), they have 7 calendar days from the day the ISO posts the list of qualified project sponsors to submit a request for the opportunity to collaborate.
	32	July 15, 2014	Deadline for joint project sponsor notifications
	33	No later than September 15, 2014	The ISO posts the list of approved project sponsors
	34	No later than October 15, 2014	The ISO releases a detailed report on the approved project sponsors selected

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 2013-2014 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 *Regional Transmission non-disclosure agreement* subheading.

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 2013-2014 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 2013-2014 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[1] 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

[1] 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. This qualification regarding the conceptual nature of the plan reflects the fact that each California transmission provider is responsible for approving transmission for the ISO Controlled Grid.

During the 2013-2014 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. Technical Studies

In this planning cycle, the following technical studies will be conducted by the ISO in a public stakeholder process:

- Reliability Assessment to identify needed reliability projects
- 33% by 2020 renewable resource analysis to identify needed policy-driven elements
- Economic Planning Study to identify needed economically-driven elements
- Long-term Congestion Revenue Rights to identify needed upgrades
- Local Capacity Requirements
- Nuclear and Once Through Cooling update (see section 4.1.11)

4.1 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.

4.1.1 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 – voltages 230 kV and higher 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
- SCE local areas:
  - Tehachapi and Big Creek Corridor;
  - Antelope-Bailey area;
  - 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

4.1.2 Frequency of the study

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

4.1.3 Reliability Standards and Criteria

The 2013-2014 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 2014-2023 planning horizon.

4.1.3.1 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:[2]

- 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); and
- TPL-004: System Performance Following Extreme BES Events (category D).

4.1.3.2 WECC Regional Business Practice

The WECC System Performance TPL-001-WECC-RBP-2[3] 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.[4]

4.1.3.3 California ISO Planning Standards

The California ISO Planning Standards specify the grid planning criteria to be used in the planning of ISO transmission facilities.[5] 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.

4.1.4 Study Horizon

The studies that comply with TPL- 001, TPL- 002, and TPL- 003 will be conducted for both the near-term (2014-2018) and longer-term (2019-2023) 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 (2014 -2018) per the requirement of the reliability standard.

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[2] http://www.nerc.com/page.php?cid=2%7C20
[3] http://www.wecc.biz/library/Documentation%20Categorization%20Files/Regional%20Business%20Practices/TPL-001-WECC-RBP-2.pdf
[4] http://compliance.wecc.biz/application/ContentPageView.aspx?ContentId=71
[5] http://www.caiso.com/Documents/TransmissionPlanningStandards.pdf

4.1.5 Study Years

Within the identified near and longer term study horizons the ISO will be conducting detailed analysis on 2015, 2018 and 2023[6]. 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 utilized past studies[7] in the areas as appropriate.

4.1.6 Study Scenarios

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

Generation:

Existing and future generation resources are modeled and dispatched to reliably operate the system under stressed system conditions. More details regarding generation modeling is provided in section 4.1.9.

Demand Level:

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.

Stressed Import path flows:

For system normal conditions (TPL-001), the study assumes that high import flows that are required to serve load in addition to internal generation resources to each study area are modeled in the base cases. This assumption represents a stressed system operating condition. This ensures that transmission facilities supporting load in these study areas can be adequately utilized under a variety of plausible system conditions to reliably serve load. Section 4.1.14 lists the MW flow on major import paths that will be modeled in the study.

[6] 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."*

[7] 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
	2015	**2018**	**2023**
Northern California (PG&E) Bulk System*	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load Summer Partial 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 Partial Peak	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
Consolidated Southern California	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak Summer Off-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.

4.1.7 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)[8]
- 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)[9], where G-1 represents the most critical generating outage for the evaluated area
- Loss of a both poles of a 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[10]

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

4.1.8 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							
		PG&E Case	Series	SCE Case	Series	SDG&E Case	Series	VEA Case	Series
2015	Summer Peak	2015HS3-S	2012	13HS2	2012	13HS2	2012	13HS2	2012
	Winter Peak	2012-13 HW2-OP	2012						
	Summer Off-Peak	2013 LS1-OP	2012	13HW2	2012	13HW2	2012	13HW2	2012
2018	Summer Peak	2018 HS2	2012	17HS1	2012	17HS1	2012	17HS1	2012
	Winter Peak	2017-18 HW2	2012						
	Summer Light	2013 LS1-OP	2012	17HW2	2012	17HW2	2012	17HW2	2012
	Summer Partial Peak	TBD							
2023	Summer Peak	2023 HS1	2012	23HS1	2012	23HS1	2012	23HS1	2012
	Winter Peak	2017-18 HW2	2012						
	Summer Off-Peak	2022 LS1-S	2011	2022 LS1-S	2011	2022 LS1-S	2011	2022 LS1-S	2011

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 2018 summer peak base case for the northern California will use 2015HS3-S 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.

4.1.9 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 provided the ISO with the RPS portfolios to be used in the 2013-2014 transmission planning process on February 8, 2013. The RPS portfolio submission letter is located on the ISO website at the following link:

http://www.caiso.com/Documents/2013-2014RenewablePortfoliosTransmittalLetter.pdf

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.

OTC Generation: Modeling of the once-through cooled (OTC) generating units follows the State Water Resources Control Board (SWRCB)'s Policy on OTC plants with the following exception:

- Base-load nuclear generation units are modeled on-line, except for the nuclear generation backup plan studies;
- Generating units that are repowered, replaced or having plans to connect to acceptable cooling technology, as illustrated in Table 4-3;
- Generating units that were identified as needed for local capacity requirements in the ISO 2011/2012 Transmission Plan related to OTC analyses (Section 3.3 of ISO 2011/2012 Transmission Plan), as illustrated in Table 4-4.

Table 4-3: Generating Units repowered, replaced or having plans to connect to acceptable cooling technology

Region	Facility	Owner	Unit	State Water Board's Compliance Date	Existing NQC Capacity (MW)	Modeling Suggestions in ISO 2013/2014 Reliability Studies
Bay Area	Contra Costa	GenOn	6	12/31/2017	337	Model on-line for 2013; Model off-line for 2014 and beyond (make sure that Marsh Landing is in-service when CC is modeled off-line)
			7	12/31/2017	337	
Bay Area	Pittsburg	GenOn	5	12/31/2017	312	Model on-line for 2013 - 2017; Model Pittsburg 7 off-line for 2018 and beyond; Model units 5 & 6 on-line for 2018 and beyond
			6	12/31/2017	317	
Central Coast	Moss Landing	Dynegy	1	12/31/2017	510	Model on-line for 2013 - 2017; Model off-line for 2018 and beyond (if reliability concerns are identified, model it on-line again to see if it helps to mitigate concerns)

Table 4-4: OTC Replacement capacity identified as needed for local capacity requirements

LCR Area	Capacity (MW)
Greater Bay Area	0
Big Creek/Ventura (Moorpark Sub-area)	430
West LA Basin / LA Basin	2370 – 3741
San Diego	531 - 950

Generation Retirements: A list of generators that are assumed to be retired is provided in Table A3-1 of Appendix A. These generators will be removed or will not be dispatched starting in the year they are assumed to be retired.

4.1.10 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 2012-2013 or earlier ISO transmission plans. Currently, the ISO anticipates the 2012-2013 transmission plan will be presented to the ISO board of governors for approval in March 2013. Once the plan is approved by the board, a complete list of transmission projects will be included in the final Study Plan.

4.1.11 Demand Forecast

Except where noted otherwise, the assessment will utilize the mid-case California Energy Demand Forecast 2012-2022 released by California Energy Commission (CEC) dated June 2012 with the Mid-Case LSE and Balancing Authority Forecast spreadsheet updated as of August 16, 2012.

In addition to the CEC Energy Demand Forecast, the ISO will also incorporate incremental uncommitted energy savings in forecast utilized in the studies. The ISO will utilize the CEC's Low-Savings identified in the Energy Efficiency Adjustments for a Managed Forecast: Estimates of Incremental Uncommitted Energy Savings Relative to the *California Energy Demand Forecast 2012-2022*, dated September 14, 2012.

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

http://www.energy.ca.gov/2012_energypolicy/documents/index.html#EnergyDemandForecast

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 each local area study in the PG&E service area for the areas studied.
- The 1-in-5 load forecast will be used for studies that address regional transmission facilities (i.e. bulk system)
- The 1-in-10 load forecasts will be used in each local area study in SCE service area
- The 1-in-10 load forecasts will be used in each local area study in SDG&E service area

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.

The ISO is considering deferring the nuclear and once through cooling update to be completed in the mid-November 2013 through May 2014 period, so that that the update can be performed using the CEC's 2013 IEPR forecast including the most up to date information on uncommitted energy efficiency. This would enable those results to be more comfortably relied upon in the 2014 LTPP proceedings. If the ISO proceeds on this path, those studies would become separate from the ISO's 2013/2014 transmission plan and be released as a separate study.

4.1.11.1 Pacific Gas and Electric Service Area

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

PG&E Loads in Base Case

The method used to determine the PG&E loads is similar to the one used in the 2011-2012 studies. The method consists of determining the division loads for the required 1-in-5 system or 1-in-10 area base cases as well as the allocation of the division load to the transmission buses.

<u>Determination of Division Loads</u>

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

<u>Allocation of Division Load to Transmission Bus Level</u>

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

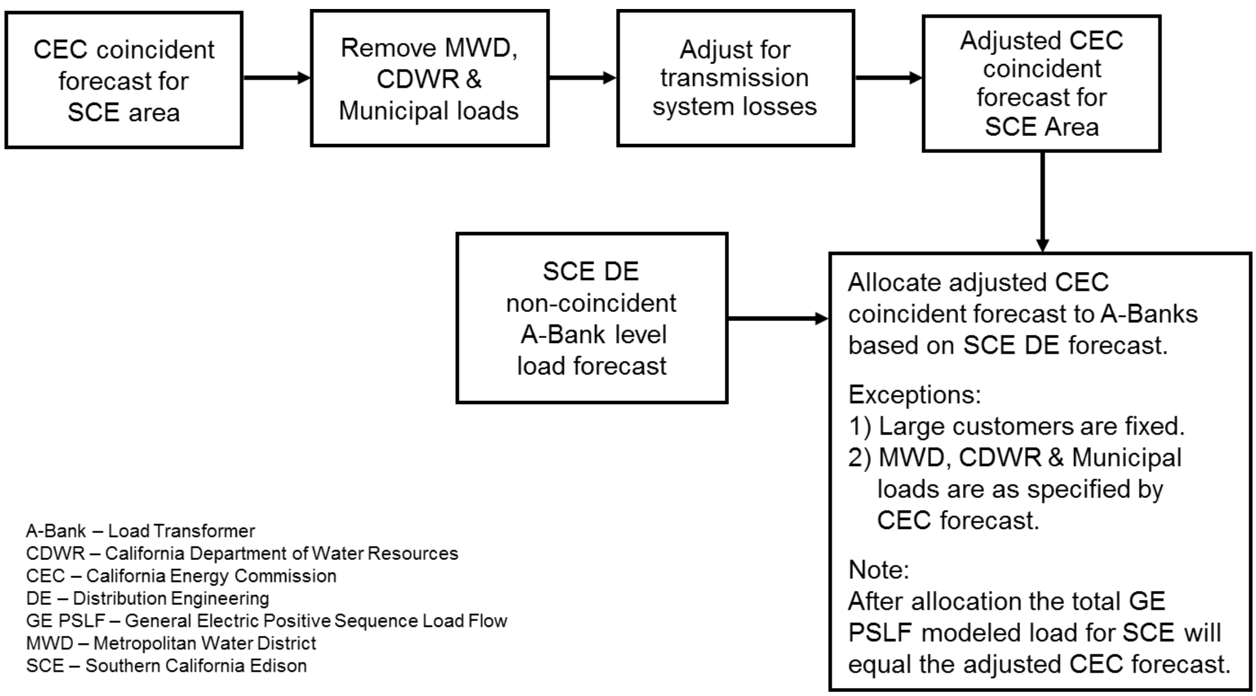
Municipalities provide PG&E their load forecast information. If no information is provided, PG&E supplements such forecast. For example, if a municipal utility provided only the 1-in-5 loads, PG&E would determine the 1-in-2 and 1-in-10 loads by adjusting the 1-in-5 loads for temperature in the same way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

4.1.11.2 Southern California Edison Service Area

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

Figure 4-2: SCE A-Bank load model



4.1.11.3 San Diego Gas and Electric Service Area

The substation load forecast reflects the actual, measured, maximum coincident load on the substation distribution transformers. This max load is obtained either from SCADA historical data or in a few cases from mechanical charts. That measured max load is then weather normalized to produce the adverse substation load. The adverse substation loads are then adjusted across SDG&E so that area loads plus losses sum to the CEC 90/10 forecast. Thus, two substation loads for each distribution bus are modeled: the adverse load, and the coincident load. The 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.

4.1.12 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.

4.1.13 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.

4.1.14 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 4-5 lists the capability and power flows that will be modeled in each scenario on these paths in the northern area assessment[12].

Table 4-5: Major Path flows in northern area (PG&E system) assessment[13]

Path	Path Flow (MW)			
	Summer Peak	Summer Off-Peak	Winter Peak	Spring Off-Peak
Path 15 (N-S)	N/A	-5400	-1000	TBD
Path 26 (N-S)	4000	-1800 to 1800	2800	800
Path 66 (N-S)	4800	N/A	TBD	1500

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.

In addition, Table 4-6 lists major paths in southern California along with the range of major path flows in the southern California system studies that were modeled in the prior cycle in the southern California system studies under various system conditions. Path flows in local area assessment cases for SCE and SDG&E system in the current cycle are expected to be similar but exact numbers won't be available until the power flow cases are completed. The ISO intends to stress each of these paths where practical and realistic to up to their full path rating or system operating limit at least in one consolidated southern California base case for the near-term planning horizon.

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

[13] 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 4-6: Major Path flows in southern area (SCE and SDG&E system) assessment

Paths	Path Rating or SOL (MW)	Flow Range in Local Cases (MW)	Target Flows in Consolidated Southern California Cases (MW)
Path 26 (N-S)	4000/-3000	-3000 to 4,000	TBD
PDCI (N-S)	3100/-3100	0 to 3,100	TBD
West of River	10623	5,000 to 9,700	TBD
East of River	9300	3,200 to 6,000	TBD
Path 42	800	150 to 1000	TBD
Path 61 (N-S)	2400/-900	550 to 1900	TBD
South of San Onofre (N-S)	2200	628 to 801	TBD
ISO - Mexico (S-N)	800/-408	-5 to 5	TBD
IID-SDGE (S-N)	270	-25 to 676	TBD
North of San Onofre (S-N)	2440	-	TBD

4.1.15 Protection System

To help ensure reliable operations, many special protection systems (SPS) have been installed in some areas. Typically, these systems trip load and/or generation by strategically tripping circuit breakers under select contingencies after detecting overloads. Some SPS are designed to operate upon detecting unacceptable low voltage conditions caused by certain contingencies. The major new and existing SPS that will be included in the study are listed in section A5 of Appendix A.

4.1.16 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 at several locations such as Potrero, Newark, Rector, Devers substations
- DC transmission line such as PDCI, IPPDC, and Trans Bay Cable Projects

4.1.17 Proposed Demand Response Programs and information the ISO received from data request

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:

- California Public Utilities Commission (CPUC)
- Pacific Gas & Electric (PG&E)
- Clean Coalition
- California Consumers Alliance
- Cal Peak Power

The CPUC provided the information in Table 4-7 on the existing programs of PG&E, SCE and SDG&E. PG&E also provided details of all of the existing demand response programs, with the capacity identified for the programs identified by CPUC. PG&E also provided bus level forecast for the demand response programs. The CPUC indicated that they could provide bus level forecasts of the demand response capacities for SCE and SDG&E; however this data may contain confidential IOU customer information and as such could only be transferred to ISO under a Non-Disclosure Agreement.

Table 4-7: 2022 aggregate demand response assumptions for programs with 30-minute-or-less response time (MW)

Utility	**Program**	**2012 capacity**	**2022 capacity**
PG&E	Aggregator Managed Portfolio – Day Of (AMP-DO) SMARTAC Base Interruptible Program (BIP)	154 72 188	154 67 231
SCE	Agricultural & Pumping Interruptible (AP-I) Summer Discount Base Interruptible Program (BIP)	42 524 589	48 636 613
SDG&E	Summer Saver Base Interruptible Program (BIP)	16 1	16 6
Total	**All 30-minute-or-less programs**	**1,586**	**1,771**

The ISO is working with the utilities, and intends to consult with industry through the course of the summer, to finalize the complete set of characteristics demand response programs 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.

The ISO will also be taking into consideration the CPUC's expectations for demand response programs in local capacity areas.

The ISO will also work with the CPUC and the utilities to address the issue of data confidentiality. Confidential information cannot be relied upon in the ISO's open and transparent planning process, so a means to address this concern will need to be developed.

The submissions by Clean Coalition and California Consumers Alliance support and advocate for the use of demand response, incremental energy efficiency and higher levels of distributed generation in the ISO Transmission Planning Program, but did not document any specific existing programs that can be relied upon at present.

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.

The submission from Cal Peak Power provides an alternative configuration 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.

4.1.18 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 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.

4.1.19 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[14] 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)[15]. 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.

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

[15] 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 or other substations such as Eagle Mountain and Julian Hinds 230 kV, Metropolitan Water District (MWD) 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 4-8 are met.

Table 4-8: 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 2013 and 2014 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. GE PSLF is the main tool for this study.

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.

4.2 Policy Driven 33% RPS Transmission Plan Analysis

4.2.1 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 2023.

In the last planning cycle, the ISO performed the 33% renewable resource analysis for 2022. To perform that study, a comprehensive planning methodology was developed that included the following key steps and that will be used in this planning cycle:

1) Establish renewable portfolios to be studied 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 will reflect such considerations as environmental impact, commercial interest and available transmission capacity, among other criteria. Multiple portfolios have previously been developed, but may need to be updated.
2) Conduct production simulation for each of the developed portfolios using the ISO unified economic assessment database with renewable portfolios modeled. The production simulation results are used to facilitate the development of power flow scenarios for the power flow and stability assessments.
3) Conduct comprehensive 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
    - Utilization assessment based on production simulation
4) Categorize any identified transmission upgrade or addition elements based on the tariff Section 24.4.6.6 requirements.

In the 2013-2014 planning cycle, similar methodology will be used to identify the transmission need to meet 33% RPS in 2023.

The CPUC and CEC provided the ISO with the RPS portfolios to be used in the 2013-2014 transmission planning process on February 8, 2013. The RPS portfolio submission letter is located on the ISO website at the following link:

http://www.caiso.com/Documents/2013-2014RenewablePortfoliosTransmittalLetter.pdf

4.2.2 Study scope

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

- Develop ISO 2023 power flow base case starting from 2023 reliability base cases to model different load conditions based on the study methodology and assumptions.
- Establish portfolios to be studied.
- Review 33% renewable transmission plan assumptions (status of projects not approved should be assessed for likelihood of moving ahead).
- Model those portfolios in production, power flow, and stability models
- Run production model and use results to guide flow and dispatch assumptions in power flow model

- 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.
- 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

4.2.3 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, beginning with the 2013-2014 planning cycle, 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 2013, 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.

4.3 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 local capacity studies will be performed at least 2 scenarios for each local capacity area:

- Summer Peak 2014 – Local Capacity Area Technical Study only
- Summer Peak 2018 – Long-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, 2013.

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, both the short-term and long-term LCR reports will be posted on the 2013-2014 ISO Transmission Planning Process webpage.

4.4 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 Economic Planning Study will conduct 8760 hourly analysis for year 2018 (the 5th planning year) and 2023 (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 2012-2013 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 studied during the 2013-2014 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.

4.5 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.

4.6 Nuclear and Once Through Cooling

As part of the 2012-2013 transmission planning cycle, two studies related to the nuclear generation backup plan were performed. One addressed the extended outage scenario of the nuclear generation in the intermediate time frame. The other considered the reliability concerns and potential mitigation options in the long term. The mid-term study is considered contingency planning for future unplanned long-term outages. The study addressed a request from the CEC 2011 IEPR. The study also incorporates once-through cooling policy implications for generating units that have compliance schedules. The long-term study was undertaken as part of the utilities' relicensing assessments. The ISO will update and refine these studies and mitigation plans in the 2013-2014 transmission planning cycle.

Approximately 30% of California's in-state generation capacity (gas and nuclear power) uses coastal and estuarine water for once through cooling. On May 4, 2010, the State Water Resources Control Board adopted a statewide policy on the use of coastal and estuarine waters for power plant cooling. The policy established uniform, technology-based standards to implement federal Clean Water Act section 316(b), which require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. The policy was approved by the Office of Administrative Law on September 27, 2010 and became effective on October 1, 2010. The policy required the owner or operator of an existing non-nuclear fossil fuel power plant using once-through cooling to submit an implementation plan to the SWRCB. The implementation plans specified an alternative that would achieve compliance by a date specified for each facility identified in the policy.

The ISO anticipates that the SWRCB policy will cause the majority of gas-fired generating units using once through cooling to come offline in order to retrofit or repower using alternative cooling technologies, or retire. The policy may also have an impact on the relicensing of units at San Onofre Nuclear Generating Station or Diablo Canyon Power Plant. The update and refinement of the nuclear studies will incorporate once-through cooling policy implications.

The ISO is considering deferring the nuclear and once through cooling update to be completed in the mid-November 2013 through May 2014 period, so that that the update can be performed using the CEC's 2013 IEPR forecast including the most up to date information on uncommitted energy efficiency. This would enable those results to be more comfortably relied upon in the 2014 LTPP proceedings. If the ISO proceeds on this path, those studies would become separate from the ISO's 2013-2014 transmission plan and be released as a separate study.

Tools

The ISO will use GE PSLF version 18 for this analysis.

5. 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 2013-2014 Transmission Planning Process

Item/Issues	SME	Contact
Reliability Assessment in PG&E	Catalin Micsa	cmicsa@caiso.com
Reliability Assessment in SCE	Haifeng Liu	hliu@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
Local Capacity Requirements	Catalin Micsa	cmicsa@caiso.com
Economic Planning Study	Xiaobo Wang	xbwang@caiso.com
Long-term Congestion Revenue Rights	Chris Mensah-Bonsu	cmensah@caiso.com
Once-through Cooling & Nuclear Sensitivity Study	David Le	Dle@caiso.com

6. Stakeholder Comments and ISO Responses

All the comments the ISO receives from stakeholders on this 2013-2014 draft study plan and ISO's responses will be posted to the following link:

http://www.caiso.com/planning/Pages/TransmissionPlanning/2013-2014TransmissionPlanningProcess.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
	Geysers 20	118

Planning Area	Generating Plant	Maximum Capacity
	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
	Wolfskill Energy Center	60

Planning Area	Generating Plant	Maximum Capacity
	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
	Oxbow Power House	6

Planning Area	Generating Plant	Maximum Capacity
	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	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 Stigg (NCPA)	21
	Pardee Power House	29
	Salt Springs Power House	42
	San Joaquin Co-Generation	55
	Simpson Paper Co-Generation	50
	Stockton Co-Generation (Air Products)	50
	Stockton Waste Water Facility	2
	Thermal Energy	21
	Tiger Creek Power House	55
	US Wind Power Farms	158

Planning Area	Generating Plant	Maximum Capacity
	West Point Power House	14
	Lodi Energy Center	280
	GWF Tracy Expansion	145
	Beardsley Power House	11
	Donnells Power House	68
	Fiberboard (Sierra Pacific)	6
	Melones Power Plant	119
	Pacific Ultra Power Chinese Station	22
	Sand Bar Power House	15
	Spring Gap Power House	7
	Stanislaus Power House	83
	Stanislaus Waste Co-gen	24
	Tullock Power House	17
	Central Valley Area Total	**3,909**
PG&E - Greater Bay Area	Alameda Gas Turbines	51
	Calpine Gilroy I	182
	Contra Costa Power Plant	680*
	Crockett Co-Generation	243
	Delta Energy Center	965
	High Winds, LLC	162
	Los Esteros Critical Energy Facility	242
	Los Medanos Energy Center	678
	Mariposa Peaker	196
	Metcalf Energy Center	575
	Oakland C Gas Turbines	165

Planning Area	Generating Plant	Maximum Capacity
	Donald Von Raesfeld Power Plant	182
	Pittsburg Power Plant	1,360
	Riverview Energy Center	61
	Ox Mountain	13
	Gateway Generating Station	599
	Area Total	**6,354**
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
	GWF Henrietta Peaker Plant	109.6
	HEP Peaker Plant Aggregate	102
	Hanford L.P.	23

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

Planning Area	Generating Plant	Maximum Capacity
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
	Rio Bravo Hydro	11
	Shell S.E. Kern River	27
	Solar Tannenhill	18

Planning Area	Generating Plant	Maximum Capacity
	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
	Basic Energy Cogen (King City)	120
	King City Peaker	61
	Sargent Canyon Cogen (Oilfields)	50
	Salinas River Cogen (Oilfields)	50
	Diablo Canyon Power Plant	2,400
	Morro Bay Power Plant	1,014
	Union Oil (Tosco)	6
	Santa Maria	8
	Vandenberg Air Force Base	15
	Central Coast and Los Padres Area Total	**6,324**

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

Planning Area	Generating Plant	Maximum Capacity
	Antelope Bailey	389.1
	Warne 1	38.0
	Warne 2	38.0
	Pandol 1	56
	Pandol 2	56
	Ultragen	41
	Omar 1G	90.8
	Omar 2G	90.8
	Omar 3G	90.8
	Omar 4G	90.8
	SYCCYN 1G	75
	SYCCYN 2G	75
	SYCCYN 3G	75
	SYCCYN 4G	75
	Pastoria Energy Facility	770
	CPC East	270
	CPC West	450
	Corum	102
	Tehachapi and Big Creek Corridor Total	**3,902**
SCE - Antelope-Bailey Area	Arbwind	21.8
	Canwind	65.0
	Enwind	47.1
	Flowind	40.8
	Dutchwind	14.0
	Northwind	19.4

Planning Area	Generating Plant	Maximum Capacity
	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
	Antelope-Bailey Area Total	**389.1**
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**
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

Planning Area	Generating Plant	Maximum Capacity
	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
	Alta 42GT	66.5
	HDPP Energy Facility	830.0
	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

Planning Area	Generating Plant	Maximum Capacity
	FPLE Green 3 Wind	6.8
	Wintec 2 Wind	16.5
	Wintec 3 Wind	11.6
	Wintec 4 Wind	16.5
	Seawest 1 Wind	44.4
	Seawest 2 Wind	22.2
	Seawest 3 Wind	22.4
	Renwind Wind	9.0
	Whitewater Wind	66
	Altamesa 4 Wind	40
	Painted Hills Wind	16.9
	Altwind QF 1	32.9
	Altwind QF 2	15.1
	Buchwind QF	17
	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

Planning Area	Generating Plant	Maximum Capacity
	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
	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

Planning Area	Generating Plant	Maximum Capacity
	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
	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

Planning Area	Generating Plant	Maximum Capacity
	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
	San Onofre Nuclear Generating Station (SONGS)	2,246
	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
	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

Planning Area	Generating Plant	Maximum Capacity
	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	**13,658**

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 (NQC)	8.3

Planning Area	Generating Plant	Maximum Capacity
	Bullmoose (NQC)	20
	Lake Hodges Pumped Storage	40
	Ocotillo Express	299
	Area Total	**3,382**

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

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

A2 Planned Generation

Table A2-1: Planned Generation

PTO Area	Project	Capacity (MW)	First Year to be Modeled
PG&E	Marsh Landing (Construction)	774*	2013
	Los Esteros Combined Cycle (Construction)	120	2014
	Russel City – East Shore EC (Construction)	600	2013
	Oakley Generation Station (Construction)	624	2014
SCE	Abengoa Mojave Solar Project (Construction)	250	2014
	El Segundo Power Redevelopment (Construction)	560	2014
	Sentinel Peaker (Construction)	850	2014
	Genesis Solar Energy Project (Construction)	250	2014
	Ivanpah Solar (Construction)	370	2013-2014
	Walnut Creek Peaker (Construction)	500	2013
SDG&E	Carlsbad (Pre-Construction)	558	2016
	Pio Pico Energy Center (Pre-Construction)	300	2016

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*
SCE	El Segundo 3	335	2014**
SDG&E	Kearny Peakers	135	2014
	Miramar GT1 and GT2	36	2014
	El Cajon GT	16	2014

Notes: * Contra Costa units 6 and 7 are scheduled to be retired when the Marsh Landing generation project is commercially available.

** El Segundo unit 3 is scheduled to be retired when the El Segundo Power Redevelopment project is 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 (expected in 2012) 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	Antelope-Bailey	Antelope-RAS
	Big Creek Corridor	Big Creek / San Joaquin Valley RAS
	North of Lugo	Bishop RAS
	North of Lugo	High Desert Power Project RAS
	North of Lugo	Kramer RAS
	Antelope-Bailey	Midway-Vincent RAS
	Antelope-Bailey	Lancaster N-2 Line Loss Tripping Scheme
	Antelope-Bailey	Palmdale N-2 Line Loss Tripping Scheme
	Antelope-Bailey	Pastoria Energy Facility Existing RAS
	North of Lugo	Reliant Energy Cool Water Stability Tripping Scheme
	Eastern Area	West-of-Devers Remedial Action Scheme
	Eastern Area	Blythe Energy RAS 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

PTO	Area	SPS Name
	Metro Area	Santiago N-2 Remedial Action Scheme
	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