

2011 ISO Transmission Plan

Draft Study Plan

Table of Content

Table of Content2

Introduction3

Section 1: Overview of 2011 ISO Transmission Planning Stakeholder Process Activities and Communications4

 1.1 Stakeholder Meetings and Market Notices4

 1.2 Stakeholder Comments.....4

 1.3 Availability of Information5

 1.4 Coordination with CTPG **Error! Bookmark not defined.**

Section 2: Technical Studies7

 2.1 Reliability Assessments7

 2.1.1 Study Scenarios7

 2.1.2 Frequency of the study8

 2.1.3 Scope8

 2.1.4 Study Horizon9

 2.1.5 Study Scenarios9

 2.1.6 Study Base Cases10

 2.1.7 Generation Projects.....11

 2.1.8 Transmission Projects11

 2.1.9 Demand Forecast.....11

 2.1.10 Reactive Resources12

 2.1.11 Operating Procedures12

 2.1.12 Firm Transfer13

 2.1.13 Protection System14

 2.1.14 Control Devices16

 2.1.15 Study Tools.....17

 2.1.16 Study Methodology.....17

 2.2 Local Capacity Requirement (LCR)19

 2.3 Economic Planning Study20

 2.4 The ISO Short-Term Plan20

 2.5 Long-Term Congestion Revenue Rights (LT-CRR).....20

 2.6 Once Through Cooling.....21

Section 3: Contact information24

Introduction

As set forth in the California ISO's Business Practice Manual for the Transmission Planning Process (BPM), the ISO Transmission Planning Process (TPP) is conducted in three stages. This document is being developed as part of the first stage of the TPP which results in the development of the unified planning assumptions that will specify technical studies to be conducted as part of the current planning cycle. The objectives of the unified planning assumptions and study plan are to clearly articulate the goals of, and agree upon assumptions for, the various technical studies to be performed as part of the second stage of the TPP cycle.

This document consists of two sections. Section 1 provides information on the stakeholder process for this stag of this planning cycle. Section 2 describes all technical studies to be conducted in the 2011 Transmission Plan, including assumptions and other key details that may associated with specific studies.

The ISO market notice is the communication tool of choice with all stakeholders involved in the TPP. As such, the ISO encourages all interested parties to complete the Market Notice subscription form which is available on the ISO Website at <http://www.caiso.com/1c67/1c678de462d10.html>. This self-registration tool allows interested parties to automatically receive updates and information from the ISO information about the TPP. Please make sure to select "ISO News and Information" to ensure you receive the most up to date information regarding the ISO's TPP.

Section 1: Overview of 2011 ISO Transmission Planning Stakeholder Process Activities and Communications

Section 1 of this document presents general information regarding stakeholder activities and communications that will occur during this planning cycle.

1.1 Stakeholder Meetings and Market Notices

During each planning cycle, the ISO will conduct at least three stakeholder meetings to present and acquire stakeholder input on the current planning effort. These stakeholder meetings are scheduled and designed around each stage 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.

Table 1-1 lists the scope, tentative schedules, and locations for the three stakeholder meetings to be conducted during the 2011 Transmission Plan. Should this schedule change, the ISO will issue a market notice announcing the new date. As such, the ISO encourages interested entities to register to receive transmission planning related market notices.

Table 1-1: Tentative scope and schedule of stakeholder meetings for the 2011 ISO TPP

Meeting No	Scope and Objectives	Tentative date
1	Discuss and agree on scope and objectives, technical studies to be performed, expected deliverables, assumptions and methodology (Unified Planning Assumptions)	2/12/10
2	Review of study results and proposed projects	September - October 2010
3	Draft 2011 ISO Transmission Plan	November 2010

Stakeholders and interested parties may participate in these meetings in person or use features such as conference call or web conference. ISO market notices will provide the necessary participation information. In addition to electronically distributing the ISO market notices to subscribers, the ISO also posts 2011 ISO Transmission Plan-related market notices on its website. Generally, market notices will be sent out to subscribers approximately three weeks prior to each stakeholder meeting.

1.2 Stakeholder Comments

The ISO will provide stakeholders with an opportunity to comment on all meetings and posted documents. 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 typically provides responses either in the final transmission plan document or within 4 weeks after the comment period. However, due to the nature of some comments that need additional work, involve coordination among entities or require policy decisions, it may take longer for the ISO to respond to such comments. Stakeholder comments received during each planning cycle and the ISO responses may be summarized in appendix of the annual transmission plan.

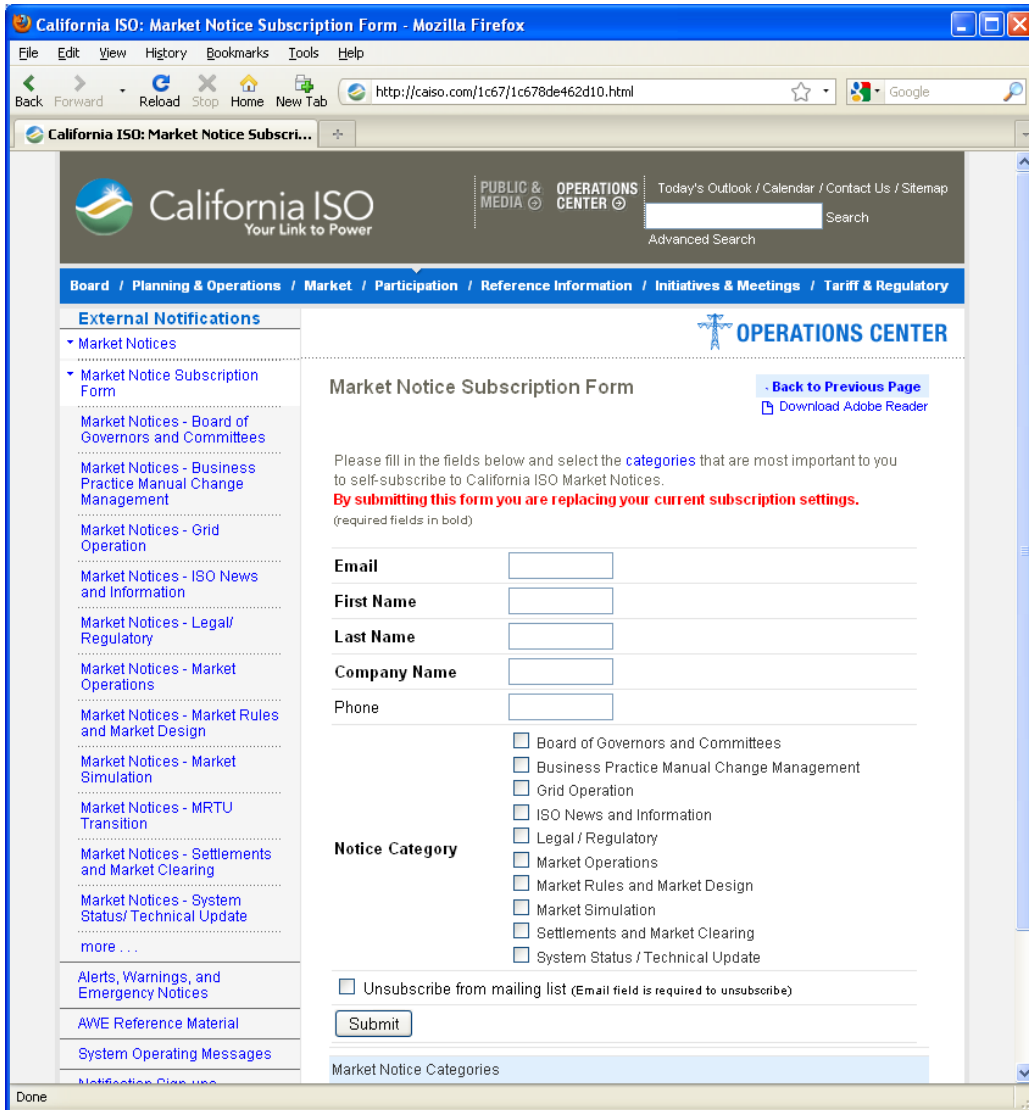


Figure 1-2 Market Notice Subscription Form

1.3 Availability of Information

The ISO Website is the central place for public and non-public information. For public information, the “Transmission Planning” (<http://www.caiso.com/1f42/1f42d6e628ce0.html>) section is the main page for documents related to TPP. Additionally, the ISO has created a secured website to store confidential or otherwise restricted data, such as Critical Energy Infrastructure Information (CEII). In order to gain access to this secured website, interested stakeholders may contact ISO at regionaltransmission@caiso.com for more information on how to access the secured section of the website¹.

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 may be limited depending on whether a requesting entity meets certain criteria set forth in the ISO tariff, engages in

¹ Starting in 2010, accessing to the ISO secured website will require digital certificate installed in each computer.

“marketing, sales, or brokering” of energy, is a Western Electricity Coordinating Council (WECC) member, or otherwise satisfies requirements for the disclosure of CEII data. Generally, to the extent other requirements are met, the ISO will require as a condition of access execution of the ISO non-disclosure agreement (NDA) and, if the data relates to WECC information and the requesting entity is not a WECC member, the WECC N-D A. Currently, the NDA form is available on the ISO website at <http://www.caiso.com/1f4f/1f4f8bf4240c0.pdf>.

Section 2: Technical Studies

In this planning cycle, the following technical studies will be conducted by the ISO:

- Reliability Assessment
- The ISO Short-term plan and Operating Guide
- Economic Planning Study
- Long-term Congestion Revenue Rights
- Local Capacity Requirements
- Once Through Cooling

More information on these studies can be found in sections 2.1 through 2.6.

2.1 Reliability Assessments

In compliance with NERC/WECC and ISO reliability criteria, reliability assessments are conducted annually to ensure that performance of the system under the ISO balancing authority area will meet or exceed the applicable reliability standards. The term “Reliability Assessments” encompasses several technical studies such as power flow, transient stability, and voltage stability studies. The basic assumptions that will be used in the reliability assessments are described in sections 2.1.1-2.1.15. Generally, these include the scenarios being studied, assumptions on the modeling of major components in power systems (such as demand, generation, transmission network topology, and imports), contingencies to be evaluated, reliability standards to be used to measure system performance, and software or analytical tools.

2.1.1 Study Scenarios

The reliability assessments will be performed on 12 study areas encompassing both the local and bulk system under the ISO balancing authority area. Figure 2-1 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 12 study areas are shown below.

- Humboldt area in PG&E service territory
- North Coast and North Bay area in PG&E service territory
- North Valley area in PG&E service territory
- Central Valley area which generally includes Sierra, Sacramento, and Stockton divisions in PG&E service territory
- Greater Bay area in PG&E service territory
- Fresno area in PG&E service territory
- Kern area in PG&E service territory
- Central Coast and Los Padres areas in PG&E service territory
- Entire northern California (bulk) system
- Southern California Edison (SCE) area
- San Diego Gas Electric (SDG&E) area
- Entire Southern California (bulk) system

Figure 2-1: Approximated geographical locations of the study areas

2.1.2 Frequency of the study

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

2.1.3 Scope

The goals of the study are to ensure that the ISO controlled grid will be reliably operated and comply with the applicable reliability standards. In general, the studies evaluate system performance under various system conditions as shown below.

- Normal conditions (TPL 001)
- Following loss of a single bulk system element (TPL 002)
- Following loss of two or more bulk system elements (TPL 003)
- Following the extreme events resulting in the loss of two or more system elements (TPL 004)

The assessment includes power flow and stability studies to assess system performance under various disturbance and non-disturbance conditions. Thermal loadings on transmission facilities, voltage magnitude, voltage deviations, and system dynamic responses are all monitored to ensure compliance with reliability standards.

2.1.4 Study Horizon

The studies that comply with TPL- 001, TPL- 002, and TPL- 003 will be conducted for both the near term (2011, 2012, 2013, 2014, and 2015) and long term (2020) scenarios. 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 (2011 through 2015).

2.1.5 Study Scenarios

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

Generation:

Generation resources are modeled and dispatched to reliability operate the system under stress system conditions. More details regarding generation modeling is provided in section 2.1.7.

Peak demand:

Since most of the ISO footprint is a summer peaking area, summer peak conditions will be evaluated in all study areas. However, winter peak, summer off-peak or summer partial-peak will also be studied for areas in where such scenarios may result in more stressed on system conditions. Examples of these areas are the coastal sub-transmission systems in PG&E service area (e.g. Humboldt, North Coast/North Bay, and central coast), which will be studied both the summer and winter peak conditions. Table 2-1 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 are adequately utilized. Section 1.1.11 lists the MW flow on major import paths that will be modeled in the study.

Table 2-1: Summary of Study Scenarios in the ISO Reliability Assessment*

Study Area	2011 through 2015	2020
Humboldt	Summer Peak Winter Peak	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak	Summer Peak
North Valley	Summer Peak	Summer Peak
Central Valley	Summer Peak	Summer Peak
Greater Bay Area	Summer Peak	Summer Peak
Fresno	Summer Peak Summer Off-Peak	Summer Peak
Kern	Summer Peak Summer Off-Peak	Summer Peak
Central Coast & Los Padres	Summer Peak	Summer Peak
Northern California (PG&E) Bulk System*	Summer Peak Summer Off-Peak	Summer Peak
Southern California Edison (SCE) area	Summer Peak	Summer Peak
San Diego Gas and Electric (SDG&E) area	Summer Peak	Summer Peak
Entire Southern California*	Summer Peak Summer Off-Peak	Summer Peak Summer Off-Peak

*The studies in these areas will be conducted on 2015 and 2020 scenarios only

Contingencies:

In addition to the system under normal conditions, the following contingencies will be evaluated as part of the study. Once the study plan has been finalized, the ISO will save these contingencies in the secured section on the ISO website

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

- Loss of one generator (G-1)
- Loss of one transformer (T-1)
- Loss of one transmission line (N-1)
- Loss of a single pole of DC lines
- Loss of the selected one generator and one transmission line (G-1/N-1), where G-1 represents the most critical generating outage for the evaluated area

Loss of two or more BES elements (Category C)

All outages of a single element will be considered in the study, which translates to a large combination of possible contingencies. These contingencies will be evaluated and the studies will focus on the contingencies that would produce more severe impacts to the grid such as:

- Loss of two transmission facilities on the same corridor
- All double circuit tower line outages
- Loss of 2 nuclear units
- Bus outages
- Selected number of two element outages (C-3 contingencies)²

Extreme contingencies (Category D)

All contingencies applicable to Category D conditions will be considered for the study. However, only the following category D contingencies that would produce the most severe impacts to the grid will be included in the study. At the minimum, the following category D contingencies will be studied:

- Loss of California-Oregon Intertie (3-500 kV lines) in Northern California Area
- Loss of 500 kV Tesla substation in Northern California Area
- Lugo Substation Outage (One voltage level plus transformers)
- North of Miguel common corridor outage (combined 230kV, 138kV and 69kV line outages)
- Loss of 3 lines South of WECC Path 26

2.1.6 Study Base Cases

The power flow base cases from WECC will be used as the starting point of the ISO transmission plan base cases. During the course of developing the transmission plan base cases, the portion of the network being examined in each scenario will be updated by the assumptions provided in this study plan. For example, a 2015 base case for the northern California will use a WECC base case as the starting point³. However, the

² The CAISO also evaluates the impact from outages of two or more elements that results from the combination of two Category B outages at the voltage level of 60 kV and above in several local areas.

³ In general, WECC power flow base cases that models the same study conditions and the same year will be used as the starting base cases for ISO planning base cases. These base cases are available for WECC members through WECC website.

network representation in northern California will be updated by the information described in this document. This practice will result in better accuracy of network representation both inside and outside the study area.

2.1.7 Generation Projects

During the past several years, the ISO has seen a large number of interconnection requests from renewable resources in its generation interconnection queue. Given the current state and federal regulations and policy regarding renewable energy, it is clear that the amount of renewable resources will increase in the generation mix. Notably, the State of California is contemplating a 33% RPS by 2020 and the ISO along with other entities in the state have begun to plan for this objective. Consequently, it would be unrealistic to assume no new renewable resources over and above those that already exist or are under construction in the long-term reliability assessment. The ISO therefore proposes that a 33% RPS scenario for renewable resources be modeled in the planning base cases in this planning cycle.

For the purposes of modeling renewable resources, for this planning cycle, the ISO will rely on information from its generation interconnection process to determine the amount and location of renewable resources in the reliability base cases. The ISO recognizes that State agencies and other entities are examining alternative portfolios; however, until those are ready and have been examined for accuracy, the ISO will proceed with the concrete data that it has. Specifically, the ISO will include in its 33% RPS portfolio the renewable generation and associated transmission in the ISO queue that is in the following stages of interconnection process:

1. For Serial interconnection studies [both the large generator interconnection process (LGIP) and the small generator interconnection process (SGIP)] – All renewable projects with all interconnection studies completed and that have either signed or are in process of signing their interconnection agreement.
2. All remaining renewable projects in Phase 2 of the ISO Transition Cluster (after posting of financial securities).

Additional information regarding non-ISO renewable generation in the similar status may be modeled using scenarios that are being developed collaboratively with neighboring entities through the The California Transmission Planning Group (CTPG). More details about these renewable generation assumptions will be provided in the final version of this study plan.

2.1.8 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 2010 or earlier ISO transmission plans. Since the 2010 transmission plan is being finalized at the time this draft study plan is being developed, the ISO will provide the list of transmission projects to be modeled in the reliability assessment in the final version of this study plan.

2.1.9 Demand Forecast

The assessment will utilize load forecast from the California Energy Commission (CEC) as the primary source to estimate future electricity demand for the system. However, 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 forecasts⁴. Where the CEC's local load forecasts are augmented by a PTO, the PTO is responsible for documenting the methodology used to augment the load forecasts. In general,

⁴ The local area load forecast was developed, using the CEC load forecast as the starting point

- 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 forecasts will be used in each local area study in PG&E service area for areas outside the study area.
- 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

2.1.10 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 2-4 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.

Table 2-4: Summary of reactive resources that will be modeled in the ISO reliability assessments

Substation	Capacity (Mvar)
GATES	225
LOSBANOS	225
GREGG	150
MC CALL	132
MESA	100
METCALF	350
OLINDA	200
TABLE MT	454
TRACY	150
DEVERS 230kV and DEVERS 500kV	156 MVAR; and 605 MVAR (based on 525kV)*
Sunrise San Luis Rey 230 kV	63
Southbay 69 kV	50
MIRALOMA	158
CENTRAL	126

* Dynamic capability

2.1.11 Operating Procedures

Operating procedures, for both normal (pre-contingency) and emergency (post-contingency) conditions, are modeled in the studies. Table 2-5 summarizes key operating procedures that will be included in the study.

Table 2-5: Normal (pre-contingency) Operating Procedures

Operating Procedure	Scope
G 206	San Diego Area Generation Requirements
G 217	South of Lugo Generation Requirements
G 219	SCE Area Generation Requirements
G 233	Bay Area Generation Requirements

Table 2-5: Normal (pre-contingency) Operating Procedures (cont)

Operating Procedure	Scope
T 144	South of Lugo 500 kV Lines
T 116	AC/DC Nomogram for N/S Flow
T 129	Fresno Area Operating Instructions (T129)
T 103	Southern California Import Transmission (SCIT)

2.1.12 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. 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 2-6 lists the capability and power flows that will be modeled in each scenario on these paths in the northern area assessment⁵.

Table 2-6: Major Path flows in northern area (PG&E system) assessment⁶

Path	Limit (MW)	Path Flow (MW)		
		Summer Peak	Summer Off-Peak	Winter Peak
Path 26 (N-S)	+4000/-3000	4000	4000	-1619
Path 66 (N-S)	+4800/-3675	4800	4800	-3679

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 1500-2000 MW to maintain the stressed Path 15 as well as to balance the loads and resources in northern California

Similarly, table 2-7 lists the capability and major path flows in the southern California system studies that were modeled in the prior cycle. They are expected to be similar for the current planning cycle but exact numbers won't be available until the power flow cases are completed.

⁵ These path flows will be modeled in both all base cases.

⁶ 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 2-7: Major Path flows in southern area (SCE system) assessment

Path	Path Flow (MW)			
	2014 Summer Peak		2019 Summer Peak	
	All Gen in Srvc	G-1 SONGS	All Gen in Srvc	G-1 SONGS
West of River (WOR)	7960	7891	8329	8330
East of River (EOR)	5684	5687	5603	5300
Pacific DC Intertie (PDCI)	3000	3000	2998	2998
Path 26	2274	3495	2348	3524
S of Lugo	4068	4415	4776	5149
Vincent - Mira Loma	419	648	458	680
SCIT	15983	17131	16859	18030

In addition, table 2-8 lists the MW flow on major paths modeled in the base cases for the study in the SDG&E system in the prior planning cycle. They are expected to be similar for the current planning cycle but exact numbers won't be available until the power flow cases are completed.

Table 2-8: Major Path flows in southern area (SDG&E system) assessment⁷

Path	Path Flow (MW)	
	2014 Summer Peak	2019 Summer Peak
Midway - Los Banos (path 15)	1909	481
Arizona - California (Path 21)	5353	4232
Northern - Southern California (Path 26)	1164	2722
IPP DC Line	1594	1594
Sylmar - SCE	-273	-188
IID - SCE	346	131
North of San Onofre	808	618
South of San Onofre	1342	1532
CAISO - Maxico (CFE)	1	1
West of River (WOR)	8477	6872
East of River (EOR)	7351	5397
Lugo - Victorville 500 kV Line	1575	1334
Eldorado - McCullough 500 kV	-78	-16
Perkins - Mead - Marketplace	424	0

2.1.13 Protection System

To help ensure reliable operations, many remedial action schemes (RAS) or 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. Table 2-9 below lists major new and existing RAS/SPS that will be included in the study.

⁷ These path flows are still being reviewed

Table 2-9: List of key protection systems modeled in the study

RAS / SPS Name	Descriptions
Middletown UVLS	Trip Middletown substation load under low voltages conditions.
Humboldt SPS	Trip load in Humboldt under low voltages conditions
Alameda Overload SPS	Drops City of Alameda load following the overload of Oakland cables.
Bay Area UVLS	Trip local distribution load. When detects low 230 kV voltage at Newark, Monta Vista, San Mateo.
Bay Meadows OL SPS	Trip one or two Bay Meadows distribution feeders. After loss of any San Mateo - Bay Meadows 115 kV line.
Eastshore 230/115 kV TB #1 and #2 Overload SPS	T&LO, and initiate breaker failure on the associated transformer high and low side breakers if loading above emergency rating. Scheme is normally cut out except for specific clearances.
Evergreen - San Jose B OL	Trip San Jose CBs 112, 122 following the OL on Evergreen - San Jose B
Gilroy Energy Center SPS	Trip up to 51 MW gen at Gilroy Energy Center if OL on Llagas - Morgan Hill or Llagas - Metcalf 115 kV lines.
Grant - Eastshore OL SPS	Trip Grant feeder breakers 1105 & 1108 if OL on Grant - Eastshore #1, #2
Metcalf - El Patio OL SPS	Trip El Patio CB 142 (El Patio - SJ A) if Load > 960 A on either Metcalf - El Patio #1 or #2 115 kV line.
Metcalf SPS	Trip load and curtail generation following the loss of Moss Landing - Metcalf or Metcalf - Tesla
Monta Vista N-2 OL SPS	Trip Monta Vista - Jefferson #1 and #2 230 kV lines following loss of both Monta Vista #3 & #4 230 kV lines.
Moraga - Oakland J OL SPS	Trip Oakland J CB 122 (Jenny) if load > 750 A on Moraga - J
Newark Dumbarton OL SPS	Trip Dumbarton CB 132 if OL on Newark - Dumbarton 115
San Francisco RAS	Trip Area Load after NERC Cat D loss of area generation or transmission.
South of San Mateo SPS	Trip up to 600 MW of load in the peninsula if 115 kV Line OL caused by N-2 230 kV outages.
Mirage Overpower /Undervoltage Relays	These relays are to prevent low voltages or line overloads in the Iron Mountain/Eagle Mountain/Julian Hinds area by tripping the Mirage-Julian Hinds 230 kV line
MWD Eagle Mountain Thermal Relay	The thermal overload relay will trip Eagle Mountain-Julian Hinds if an overload is detected on the Iron Mountain-Eagle Mountain 230 kV line.
West of Devers Overload Protection Scheme ("WOD SPS")	The WOD SPS was put in service in June 2007. The objective of this scheme is to mitigate the existing overloads on West of Devers 230 kV lines. The WOD SPS includes tripping of two Devers 500/230 kV AA transformer banks under certain system configuratio

Table 2-9: List of key protection systems modeled in the study (cont)

RAS / SPS Name	Descriptions
South of Lugo (SOL) N-2 SPS	This remedial action scheme was put in operation in June 2005 to trip up to 3 "A" station loads (Mira Loma, Padua, and part of Chino) for a total of about 1100MW to 1400MW if any two 500 kV lines were lost on the South of Lugo path.
Mariposa UVLS	Trip load in the area if under voltages detected
Ashlan 230 kV UVLS	Trip load in the area if under voltages detected
McCall 230 kV UVLS	Trip load in the area if under voltages detected
Stagg UVLS	Monitor the Stagg 230 kV bus voltage and curtail load to mitigate post-contingency low voltage problems which could result from a sustained outage to the Tesla - Stagg and Tesla – Eight Mile Road 230 kV Line.
Blythe SPS	There is an existing Blythe SPS to mitigate the overload on the lines out of Blythe 161 kV. In 2010, the Blythe I project will leave the Western Area Power Administration, Lower Colorado (WAPA LC) control area and connect to Julian Hinds 230 kV with a gen
Low Voltage Load Shedding (LVLS) Scheme.	This remedial action scheme was put in operation in the mid-1980's to prevent a low-voltage condition resulting from the simultaneous loss of the Lugo-Mira Loma 2&3 and Lugo-Serrano (or Lugo-Mira Loma 1, after Lugo-Serrano is looped in at Mira Loma) 500 k
Yolo 115 kV UVLS	Trip load in the woodland area if under voltages detected
Figarden 230 kV UVLS	Trip load in the area if under voltages detected
500kV TL 50001 IV Generator SPS	Trip generation at CLR II and TDM under contingency conditions
Miguel transformer protection	Monitors the loss of transformer and the loading on the remaining transformer
Otay Mesa – Tijuana SPS	A redundant scheme is installed to protect the line from loading above its continuous rating
TL 649 69 kV SPS	An SPS to protect TL 649 from thermal overload for an outage of TL 6910

2.1.14 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 Transbay Projects

2.1.15 Study Tools

Basically, 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 and transient stability studies. However, other tools such as DSAT 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 bulk assessments, governor power flow will be used to evaluate system performance under normal conditions and following the contingencies of equipment at voltage level 230 kV and higher.

2.1.16 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 which are based on the reliability standards established by NERC and WECC, as well as local reliability criteria⁸ for all local areas studied in 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 ranges. Under ISO planning standards, a combined N-1 and G-1 is considered a Category B event. The study simulates all single contingencies in the area (include considering all combination of N-1 and G-1 contingencies), all double circuit tower line outages plus all combinations of any two elements (generator, line, transformer) out as well as combinations of any one element out followed by double circuit tower line outages. Depending on the type and technology of power plant, several G-1 contingencies represent an outage of the whole power plant (multiple units). Examples of these outages are 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.

In addition, in the SDG&E area, the studies will be performed for two import operating conditions: simultaneous (SIL) and non-simultaneous import (NSIL) limit conditions. With the proposed Sunrise Power Link plan of service, SDG&E's simultaneous import capability will increase from 2850 MW to 4200 MW. For a more conservative assumption, the simultaneous import limit was modeled at 4000 MW which represents the stressed system conditions. Non-simultaneous import limit studies modeled Southwest Power Link (SWPL) out of service with the generation adjusted. The import limit into SDG&E under these conditions will be reduced to 3500 MW to be consistent with existing operating procedures. The import capability limit (ICL) is defined as the import limit following the most limiting Category B event (N-1 or G-1*/N-1) with the system readjusted to within continuous ratings and path ratings, such that the system meets Category B performance criteria. Operating the system within the ICL will allow for meeting the reliability criteria for a subsequent contingency. In the SDG&E area, power flow studies will be also performed for several versions of the generation dispatch of the large power plants (Otay Mesa, Encina and Palomar).

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. For the SCE system, the voltage deviation of 7% for "N-1" contingencies is observed⁹ and 10% for "N-2" contingencies.

⁸ California ISO Planning Standards are posted on the CAISO website at <http://www.caiso.com/docs/09003a6080/14/37/09003a608014374a.pdf>

⁹ Per SCE Guidelines for voltage deviation of 7% for "N-1" contingencies

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.

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

The Guide to WECC/NERC Planning Standards I.D: Voltage Support and Reactive Power, approved by WECC TSS on March 30, 2006, will be utilized for the analyses in the ISO balancing authority area. According to the guideline, load will be increased by 5% and all Category B contingency 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 such as Rio Oso, Fresno or San Diego areas.

Transient Stability Analyses

Transient stability runs 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 2-10 are met.

Table 2-10: WECC Transient Stability Criteria

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

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

Power Factor Assumption

In SCE area assessment, a 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 six years has ranged between 12.2 in 2000 to 38 in 2005 during the annual peak load for each year. The increase in the WATT/VAR ratio is a result of SCE initiating an aggressive program, as described below, to ensure that this value of 25-to-1 will be validated. This program is based on SCE’s commitment to optimize VAR planning and capacitor bank availability during Heavy Summer peak load periods in the Distribution and Sub-transmission systems.

Recent Historical System WATT / VAR Ratio:

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

- 2004 – leading pf
- 2005 – 38
- 2006 – 28.9

- 2007 – 52
- 2008 – 42

The objective of SCE Program is to ensure 25-to-1 WATT / VAR Ratio

In the SDG&E area, power factors at all substations will be modeled at nearly all load busses at 0.995 lagging. The 0.995 lagging value is based on actual system power factor during system peak conditions. In addition, SCADA-controlled distribution capacitors are installed at each substation with sufficient capacity to compensate for distribution transformer losses. The exceptions listed below will be modeled using power factors indicative of historical values which is consistent with the power factor model used by SDG&E

- Naval Station Metering (bus 22556): 0.707 lagging (this substation has 24 MVAR shunt capacitor)
- Creelman (bus 22152): 0.992 leading
- Descanso (bus 22168): 0.900 leading
- Rincon (bus 22688): Unity

2.2 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 on 3 scenarios for each local area:

- Summer Peak 2011 – Local Capacity Area Technical Study only
- Summer Peak 2013 – Long-Term Local Capacity Requirements
- Summer Peak 2015 – 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 short-term LCR (Summer Peak 2011 scenarios) approximately by May 1, 2010. Long-term LCR studies will be conducted later, and the study results will be presented to stakeholders at the second TPP meeting.

Load Forecast: The CEC load forecast is the primary source of future demand modeled in the base cases. However, since the primary focus of the LCR study is to determine capacity requirements in the local areas, load forecasts in each local area, described in section 2.1.8, will be used in the study.

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/2488/2488bcca65490.pdf>.

Tools: GE PSLF version 17 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 at the 2011 ISO Transmission Plan webpage.

2.3 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. This study will rely on the same methodology that was discussed with the TPP during the previous planning cycle, but updated to consider the most recent results of the state-wide transmission planning to achieve the 33% RPS. For more information regarding the scope and methodology of the Economic Planning Study, please refer to section 2.3 of the 2010 final study plan (<http://www.caiso.com/2374/2374ed1b83d0.pdf>).

2.4 The ISO Short-Term Plan

During 2009 the ISO realigned its operational engineering and regional transmission planning resources to more effectively address operational and planning needs within the ISO's new market. As a result, the ISO has also revisited the objectives of the Short-Term Plan with the intent that it reflects the realignment structure as well as accommodates operational knowledge gained through the availability of the ISO market information. Overall, the focus of the ISO short-term plan remains unchanged, that being to address reliability and congestion concerns. However, the responsibility for the short-term plan, while lying mostly with the Market and Infrastructure Development, will be shared with Grid Operations.

As currently envisioned, the short-term plan will be broken into two areas of responsibility that are defined by a specific time horizons. The first time horizon will encompass what the ISO considers year "0" through year "1". Grid Operations will assume responsibility for this part of the short-term plan which will focus on reliability and congestion issues during the current operating year. From a methodological perspective, a "look-back" and "look-forward" approach will be used. A look-back over the previous year's operation will be made to assess and address operational concerns that may arise in the forthcoming or look-forward operating season. As in previous short-term plans, the objective is to identify and propose solutions within the current year's operating season.

The second time horizon will encompass year "1" through year "5". This part of the short-term plan is intended to address, in greater detail, the near term horizon as mentioned in Section 2.1.4. Close coordination across the entire short-term plan time frame is intended to ensure that operational concerns that may require consideration of infrastructure improvements across a longer period of time, such as the need for a new substation or transmission line, will be appropriately addressed in the ISO's transmission plan.

2.5 Long-Term Congestion Revenue Rights (LT-CRR)

The ISO is obligated to ensure the continuing feasibility of long term CRRs that are allocated by the ISO over the length of their terms. In furtherance of this requirement, the ISO shall, as part of the current planning cycle, test and evaluate the simultaneous feasibility of allocated Long Term CRRs 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. Pursuant to such evaluations, the ISO shall identify the need for any transmission additions or upgrades required to ensure the continuing feasibility of allocated long term CRRs over the length of their terms. In assessing the need for transmission additions or upgrades to maintain the feasibility of allocated long term 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; RAS/SPS; constrained-on generation; interruptible loads; reactive support; or in cases where the infeasible long term 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 ISO tariff section 11.2.4 The PTOs and market participants shall provide the necessary assistance and information to the ISO to allow it to assess and identify transmission additions or upgrades that may be necessary.

Scenarios: Consistent with the BPM, the following studies will be performed:

- Add planned transmission network changes to the CRR network model with all facilities in-service. (2 years out and 5 years out)
- Apply long term CRR encumbrances on the system including existing transmission contracts [ETCs] and converted rights [CVRs], which would be modeled as fixed CRRs. Since long term CRRs are allocated separately for each combination of season (i.e., calendar quarters) and time of use (on-peak or off-peak), there are eight distinct sets of long term CRRs to be modeled.
- Run SFT on models for each combination of season and time-of-use with peak and off-peak encumbrances separately.

It is expected that these sets of long term CRR encumbrances will be feasible. If the long term CRRs are not fully feasible, then depending on the severity of the infeasibility the ISO will consider the most appropriate mitigation from the alternatives noted above. To the extent a transmission upgrade or addition is deemed needed to maintain the feasibility of allocated long term CRRs in accordance with this section and is included in the ISO's annual transmission plan, the ISO will designate the PTO(s) with a PTO service territory in which the transmission upgrade or addition is to be located as the project sponsor(s), responsible to construct, own and/or finance, and maintain such transmission upgrade or addition.

Load Forecast: Load forecasts on the years being studied will be modeled in the base case. CRRs are source to sink financial instruments. The sink portion of this transaction represents the load.

Generation Assumptions: Similar generation assumptions used in section 2.1.7 will be used in the study. CRRs are source to sink financial instruments. The source portion of this transaction represents either generation or imports.

Transmission Projects: ISO-approved transmission projects will be modeled in the base case. The same transmission project assumptions that have been used in the reliability assessments will be used. Transmission project change files for all projects approved by the ISO and the date they are expected to be in-service will be used for this study.

Imports: Import levels similar to what have been described in section 2.1.11 will be used in the study. CRRs are source to sink transactions. The source portion of this transaction represents the generation and imports.

Contingency List: Contingencies will be handled consistent with the CRR SFT methodology.

Tools: GE PSLF, Siemens PTI, and SFT software engine.

2.6 Once Through Cooling

Approximately 30% of California's in-state generation capacity (gas and nuclear power) uses coastal and estuarine water for once through cooling. On June 30, 2009, the State Water Resources Control Board (SWRCB) issued a draft policy that imposes best technology available requirements on electric power plants to minimize the adverse environmental impacts of once through cooling.¹⁰ The SWRCB issued revisions to the draft policy on November 23, 2009. The draft policy identifies two compliance alternatives for existing power plants to attain best technology available: (1) reduce intake flow rate to a level that can be attained by a close-cycle wet cooling system; (2) if an owner or operator demonstrates that the first compliance option is not feasible, use operational or structural controls to reduce impingement mortality and entrainment for all life stages of marine life for the facility to a comparable level to that which would be achieved under the first compliance option.

Nuclear units may also seek to establish site specific requirements for best technology available, if the owner or operator demonstrates that compliance with the draft policy would result in a conflict with a safety

¹⁰ See http://www.swrcb.ca.gov/water_issues/programs/npdes/cwa316.shtml

requirement established by the Nuclear Regulatory Commission. The draft policy also directs Pacific Gas and Electric Company and Southern California Edison to conduct special studies to investigate alternatives for the nuclear units to meet the requirements of the draft policy, including the costs for these alternatives.

The ISO anticipates the SWRCB will adopt a once through cooling policy during the first or second quarter of 2010. If adopted, the ISO anticipates that the SWRCB policy will force 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 ISO needs to assess the reliability impacts to the ISO grid that may result from any retrofits, repowers or retirements.

Another consideration arising from the SWRCB draft policy is the connection between generating units using once-through cooling and renewable integration. First, many of the units using once-through cooling technology have the characteristics needed to provide the ramping and regulation services needed for renewable integration. Replacement infrastructure will need to retain or improve these capabilities (whether by the repowered plants or replacement capacity). Second, because of the contribution of these units to system operations, it will be essential to sequence any retrofit or repowering efforts or retirements in a manner consistent with the operational requirements created by an expanding portfolio of renewables. There may be years in which such requirements are higher than in other years, due to the mix of renewables on the system. The process of complying with the SWRCB once-through cooling policy is thus another factor to consider in preparing the power system for higher levels of renewable resources.

For purposes of the 2011 transmission planning process, the ISO intends to initiate a scenario analysis to assess if and when gas-fired generation using once through cooling may come off line to retrofit, repower or retire in the ten-year planning horizon. This analysis will use a range of planning scenarios and assumptions that span a ten year time horizon. The ISO anticipates that future transmission studies will also consider the SWRCB policy and that additional facts such as generator plans to implement the draft policy will inform future analyses. The ISO expects the assumptions in its scenario analysis will change but believes it is important to commence this effort given the long planning horizon to deploy energy infrastructure needed to maintain reliability. It is possible that transmission additions or upgrades, generation re-powering, or electrically equivalent new generation, may serve to address reliability needs arising from potential retirements of gas-fired units using once through cooling technology. The ISO also anticipates that the CPUC, as part of its Long-Term Procurement Plan proceeding (LTPP) cycle, will consider procurement needs to accommodate the adoption of a SWRCB policy.

Approximately 30% of California's in-state generation capacity (gas and nuclear power) uses coastal and estuarine water for once through cooling. On June 30, 2009, the State Water Resources Control Board (SWRCB) issued a draft policy that imposes best technology available requirements on electric power plants to minimize the adverse environmental impacts of once through cooling.¹¹ The SWRCB issued revisions to the draft policy on November 23, 2009. The draft policy identifies two compliance alternatives for existing power plants to attain best technology available: (1) reduce intake flow rate to a level that can be attained by a close-cycle wet cooling system; (2) if an owner or operator demonstrates that the first compliance option is not feasible, use operational or structural controls to reduce impingement mortality and entrainment for all life stages of marine life for the facility to a comparable level to that which would be achieved under the first compliance option.

Nuclear units may also seek to establish site specific requirements for best technology available, if the owner or operator demonstrates that compliance with the draft policy would result in a conflict with a safety requirement established by the Nuclear Regulatory Commission. The draft policy also directs Pacific Gas and Electric Company and Southern California Edison to conduct special studies to investigate alternatives for the nuclear units to meet the requirements of the draft policy, including the costs for these alternatives.

The ISO anticipates the SWRCB will adopt a once through cooling policy during the first or second quarter of 2010. If adopted, the ISO anticipates that the SWRCB policy will force the majority of gas-fired generating units using once through cooling to come offline in order to retrofit or repower using alternative cooling

¹¹ See http://www.swrcb.ca.gov/water_issues/programs/npdes/cwa316.shtml

technologies or retire. The ISO needs to assess the reliability impacts to the ISO grid that may result from any retrofits, repowers or retirements.

Another consideration arising from the SWRCB draft policy is the connection between generating units using once-through cooling and renewable integration. First, many of the units using once-through cooling technology have the characteristics needed to provide the ramping and regulation services needed for renewable integration. Replacement infrastructure will need to retain or improve these capabilities (whether by the repowered plants or replacement capacity). Second, because of the contribution of these units to system operations, it will be essential to sequence any retrofit or repowering efforts or retirements in a manner consistent with the operational requirements created by an expanding portfolio of renewables. There may be years in which such requirements are higher than in other years, due to the mix of renewables on the system. The process of complying with the SWRCB once-through cooling policy is thus another factor to consider in preparing the power system for higher levels of renewable resources.

For purposes of the 2011 transmission planning process, the ISO intends to initiate a scenario analysis to assess if and when gas-fired generation using once through cooling may come off line to retrofit, repower or retire in the ten-year planning horizon. This analysis will use a range of planning scenarios and assumptions that span a ten year time horizon. These planning scenarios will reflect demand-side policy initiatives and alternative renewable development patterns. The ISO anticipates that future transmission studies will also consider the SWRCB policy and that additional facts such as generator plans to implement the draft policy will inform future analyses. The ISO expects the assumptions in its scenario analysis will change but believes it is important to commence this effort given the long planning horizon to deploy energy infrastructure needed to maintain reliability. It is possible that transmission additions or upgrades, generation re-powering, or electrically equivalent new generation, may serve to address reliability needs arising from potential retirements of gas-fired units using once through cooling technology. The ISO also anticipates that the CPUC, as part of its Long-Term Procurement Plan proceeding (LTPP) cycle, will consider procurement needs to accommodate the adoption of a SWRCB policy.

Section 3: Contact information

This section lists the Subject Matter Experts (SMEs) for each technical study or major stakeholder activities addressed in this document. In addition to the extensive discussion and comments period during and after various ISO Transmission Plan-related Stakeholder meetings, stakeholders may contact these individuals directly for any further questions or clarifications.

Table 3-1: SMEs for technical studies and major activities in 2010 ISO Transmission Plan

Item/Issues	SME	Contact
ISO Transmission Plan (Overall and any topic not listed in this table)	Paul Didsayabutra	PDidsayabutra@caiso.com
ISO Reliability Assessment	Paul Didsayabutra (Northern Area) David Le (Southern Area)	PDidsayabutra@caiso.com DLe@caiso.com
Request Window	Dana Young	DYoung@caiso.com
ISO Secured Website	Dana Young	DYoung@caiso.com
Local Capacity Requirement Study	Catalin Micsa	CMicsa@caiso.com
Economic Planning Study	Xiaobo Wang David Le	XBwang@caiso.com DLe@caiso.com
Long-Term Congestion Revenue Right Study	Chris Mensah-Bonsu	CMensah@caiso.com
CAISO Short-Term Plan	Bryan Fong	BFong@caiso.com
Once Through Cooling	David Le	DLe@caiso.com